EXHIBIT

AAE-1

BEFORE THE

NEW ORLEANS CITY COUNCIL

Proposed Rulemaking to Establish	)	
Integrated Resource Planning	)	**Docket No. UD-08-02**
Components and Reporting Requirements	)	
for Entergy New Orleans, Inc.	)	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE ALLIANCE FOR AFFORDABLE ENERGY

Resource Insight, Inc.

DECEMBER 22, 2010

TABLE OF CONTENTS

I. Identification and Qualifications 1

II. Introduction 2

III. Integrated Planning and the Role of Energy Efficiency 5

IV. Energy-Efficiency Screening 13

A. Avoided Costs 13

B. Screening Tests 22

V. Cost Recovery for Energy-Efficiency Programs 25

A. Program Costs 25

B. Lost Revenues 26

C. Incentives 35

1. The Purpose of Shareholder Incentives for Demand-Side Management 35

2. Incentive Structure 37

VI. Generation Planning Issues 41

A. Planned Combined-Cycle Addition in 2015 42

B. Potential Retirement of Coal Plants 46

C. Supply Diversity and Local Generation 47

TABLE OF EXHIBITS

Exhibit PC-1 *Professional Qualifications of Paul Chernick*

I. Identification and Qualifications

Q: Mr. Chernick, please state your name, occupation and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., Five Water Street, Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, integrated resource planning, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, conservation program design and ratemaking, cost recovery for utility efficiency programs (including lost revenues and performance incentives), the valuation of environmental externalities from energy production and use, and allocation of costs of service between rate classes and

1 jurisdictions. My professional qualifications are further summarized in Exhibit
2 PC-1.

3 **Q: Have you testified previously in utility proceedings?**

4 A: Yes. I have testified over two hundred times on utility issues, before regulators
5 in thirty US jurisdictions and five Canadian provinces. My previous testimony is
6 listed in my resume.

7 **Q: Have you testified previously before this Council?**

8 A: Yes. I testified in the City Council's Dockets CD-85-1 on electric cost
9 allocation, and UD-92-2A and -2B on the 1995 IRP of New Orleans Public
10 Service, the predecessor of Entergy New Orleans (ENO).

11 **Q: Have you been involved in other matters related to Entergy?**

12 A: Yes. I have testified in a number of Arkansas dockets concerning Entergy
13 Arkansas (and often all Arkansas utilities) energy-efficiency programs,
14 concerning program-design issues, estimation of energy savings, avoided costs,
15 recovery of lost revenues, and utility incentives. I have also worked on the
16 evaluation of Entergy's proposal to extend the life of the White Bluff coal plant
17 by major investments in environmental retrofits, including the economics of
18 alternatives.

19 II. Introduction

20 **Q: On whose behalf are you testifying?**

21 A: My testimony is sponsored by the Alliance for Affordable Energy.

22 **Q: What subjects will you be covering?**

23 A: The Alliance has asked me to address the following issues with relation to the
24 Integrated Resource Plans (IRPs) for ENO and Entergy Louisiana LLC (ELL), in

the context of the Entergy 2009 Strategic Resource Plan (SRP) and 2009 SRP Refresh:

- the purpose of integrated resource planning and the role of energy efficiency in IRP;
- the screening of energy-efficiency measures and programs;
- the recovery of energy-efficiency costs and related lost revenues, and the structuring of incentives to reward superior utility performance;
- generation planning issues within the IRP.

I interpret the IRPs to include the following documents, which I list by the titles used on ENO's web site, with additional explanation as necessary: [1]

- 2009 System Resource Plan Refresh Supplement Final (or "2009 Strategic Resource Plan Refresh")
- Entergy New Orleans Energy Forecasting Methodology
- Entergy New Orleans Retail Forecasting Model Summary ("ENOI Energy Forecasting Methodology")
- Entergy New Orleans Potential Study[2]
- 2009 Entergy New Orleans IRP ("Entergy New Orleans, Inc.: An Integrated Resource Plan (2009 – 2028)")
- 2009 Entergy Louisiana IRP ("Entergy Louisiana, LLC.: An Integrated Resource Plan (2009 – 2028)")
- Chapters 1–12 (the 2009 Strategic Resource Plan)

---

[1]<http://entergy-neworleans.com/irp/irp_2010.aspx> accessed 12/2010. Several documents do not have cover pages, and the 2009 SRP is not specifically identified either on the web site or in the document itself.

[2]"Entergy New Orleans Demand Side Management Potential Study: Summary," ICF Resources, April 28, 2009.

1 I will refer to ENO and ELL collectively as Entergy; I will try to be clear
2 when I am referring to the Entergy system, the parent corporation, or other
3 affiliates.

4 **Q: Please summarize your testimony.**

5 A: The purpose of the IRP is to develop the plan for meeting future requirements for
6 energy services, considering cost, risk and other factors. Energy efficiency is
7 low in cost and risk, and should be fully exploited in the IRP, in an efficient and
8 consistent manner.

9 Entergy's plans for energy-efficiency savings are very modest by national
10 standards, and should be substantially increased.

11 Aspects of Entergy's avoided costs appear to be understated. Entergy
12 should re-estimate its avoided costs in collaboration with the Council Advisors,
13 the Alliance, and other interested parties.

14 All the costs and benefits of energy-efficiency investments—including
15 benefits to participants—should be included in screening measures and
16 programs under the total resource cost test. The program administrator cost test
17 should be used to determine whether incentives are excessive.

18 The Council should allow for prompt recovery of prudently incurred
19 program costs, preferably with the assistance of a collaboration among the
20 parties. Entergy should also be able to recover its actual lost revenues, based on
21 the best estimates after the fact, or its revenues should be decoupled from sales.
22 Entergy also should be eligible for rewards for superior performance. Given the
23 vast potential benefit to ratepayers of improved energy efficiency, the Council
24 should adjust ratemaking procedures to be consistent with major energy-
25 efficiency investments.

Monitoring, verification, and evaluation of savings are essential to both lost-revenue recovery and incentive computations, as well as to program design and refinement. To maximize the quality and credibility of the savings estimates, the monitoring, verification, and evaluation functions should be administered by non-utility contractors selected by the Council and advised by the non-utility parties.

Entergy's IRP includes the addition of combined-cycle capacity in 2015 by both ENO and ELL, without demonstrating that the capacity is needed or economically beneficial. The Council should not approve those additions.

The IRPs should also be strengthened in their treatment of potential coal retirement, supply diversification and local generation, including renewables, a solar feed-in tariff, and promotion of combined heat and power and district-cooling systems.

III. Integrated Planning and the Role of Energy Efficiency

Q: What is the purpose of integrated resource planning?

A: Integrated resource planning (IRP) is the process of selecting the best (or at least a superior) combination of all resources to meet customers' energy-service needs over an extended period. In the early years of IRP, "best" was often assumed to mean "least cost" under expected conditions, and many IRPs have been referred to as "least-cost plans." Over time, experience taught the following lessons:

- Average cost under the range of plausible future situations was a more important measure of plan benefit than cost under the most likely conditions.
- Variability of costs over time and uncertainty in the total cost of plan were important, as well as the expected total cost.

- Factors other than cost—such as reducing pollutants, supporting employment, and building capability to incorporate emerging technologies—are also important in defining the "best" plan.

Ideally, all of these considerations—expected cost, stability, uncertainty, environmental concerns, employment, and innovation—will be considering in choosing among alternative plans.

Q: What is integrated in an integrated resource plan?

A: In addition to an integrated review of the benefits of the plan, as I discuss above, an IRP would consider all available resource options: existing power plants, purchases of power plants, retirement or deactivation of existing plants, short- and long-term wholesale power purchases and sales (of system power or power from a specific unit), demand management and energy efficiency.

Prior to the development of integrated resource planning, the common assumption was that each utility would build new generation (perhaps co-owned with other utilities) to meet its customers' growing requirements and that the utility would select the type of generation to add. Integrated resource planning largely originated in reaction to a series of problems that started in the mid-1970s, including overbuilding of capacity, rate increases due to oil and gas price increases, nuclear cost overruns and construction delays, utility reluctance to deal fairly with non-utility generators, and utility failure to aggressively pursue end-use efficiency options. Legislators and regulators recognized the need to identify needs for capacity and opportunities for reducing power cost in a consistent manner, and to bring the most promising options to fruition.

Q: What is the role of energy efficiency in an IRP?

A: For most utilities, large amounts of energy-efficiency will be the lowest-cost available resource. In short, bills are lower with increased efficiency. Energy-

1 efficiency also tends to reduce the volatility of bills, the uncertainty of costs
2 over time, and the environmental costs of meeting energy-service needs. Hence,
3 an IRP should include essentially all the achievable cost-effective efficiency
4 savings over the life of the plan.

5 **Q: Does that mean that Entergy should implement as much energy efficiency**
6 **as possible, as fast as possible?**

7 A: No, for a couple reasons. First, energy-efficiency-portfolio design, like most
8 important undertakings, presents trade-offs between short-term results and
9 overall net benefit. Throwing lots of resources at a problem in the short term can
10 produce quick results but increases costs and disruption and perhaps produces an
11 inferior final product.[3] Effective energy-efficiency programs require the ramp-
12 up of delivery infrastructure, training, continuous improvement driven by
13 careful evaluation of program processes and results, marketing (including word-
14 of-mouth referrals), and decision-making by participants and trade-allies, all of
15 which take time. And at all levels of the energy-efficiency process, from
16 planners to regulatory review to program management to project management,
17 only a limited amount of time and effort is available in any one year. Hence,
18 Entergy cannot simply implement all cost-effective energy efficiency in 2011, or
19 even 2011–2015, and then move on to other resource projects.

20 Second, energy-efficiency opportunities arise in two different ways. Some
21 are just sitting around, available whenever Entergy implements an effective
22 program to capture them. Examples of these retrofit opportunities include
23 replacing old fluorescent lamps and fixtures with modern efficient equipment,
24 sealing leaky ducts, insulating uninsulated walls and under-insulated ceilings,

---

[3]Imagine repaving half the streets of New Orleans in one night.

and reducing air infiltration into buildings. Another large set of energy-efficiency opportunities arise when new equipment is installed, new buildings are built, old buildings are renovated or rehabbed, and existing equipment wears out and must be replaced. These market-driven opportunities must be captured when they arise, or they are lost for a long time (in the case of new construction, essentially forever). Hence, energy-efficiency programs must be operated over long periods of time to capture opportunities as they arise.

Third, even retrofit opportunities change over time, as new technologies emerge and become cost-effective. For example, over the last couple decades, compact fluorescent lamps have become available in smaller sizes and dimmable designs, so even a consumer who installed compact fluorescents in every fixture that would accommodate them in 2005 may have additional opportunities today.

Q: What are the priorities for Entergy energy-efficiency programs over the next few years?

A: Alliance witness Hale Powell addresses this topic in detail in his testimony. In brief, Entergy should be concentrating on the following objectives:

- building capability internally and among trade allies and contractors;
- supplementing the near-term programs (Energy Smart, the Home Energy Rebate Option programs from the Department of Natural Resources, and the BetterBuildings program from the Southeast Energy Efficiency Alliance) to ramp up non-residential options and to capture market-driven opportunities that cannot be deferred;[4]

[4]As I described above, many efficiency opportunities arise when equipment and buildings are added, replaced or refurbished, and can either be captured then—or lost—for many years.

- developing ways to for collaborating with stakeholders on program design and evaluation, including the selection of independent evaluators;
- transitioning from the near-term programs to continuing utility-funded programs, to ensure continuity in program delivery, maintain momentum, and avoid abandoning the labor force and supply chain that will be developed.

Entergy's resource plans should include load reductions approximating the results of aggressive, cost-effective programs—comparable to the best programs nationally—extending throughout the forecast period. The continuing rebuilding of New Orleans presents unusually rich opportunities for establishing New Orleans as a center for energy efficiency.

Q: Are Entergy's energy-efficiency goals consistent with the plans of leading jurisdictions nationally?

A: No. Entergy's savings plans are modest compared to those of many other jurisdictions, including some with long histories of extensive savings (e.g., California, Massachusetts, Vermont) as well as others with little DSM experience (e.g., Illinois, Indiana). Table 1 shows the ratio of target energy-efficiency savings to retail sales for twenty U.S. states and ENO. Most of these states are targeting savings in excess of 1% in at least some years, and several have annual targets over 2%, far more aggressive than Entergy's plan, which averages just over 0.1%.

1 **Table 1: Comparison of DSM Target Savings Ratios**

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
AZ		1.03%	1.02%	1.20%	1.58%	1.56%	1.54%	1.51%	1.49%	1.47%	1.45%	1.43%
AR		0.25%	0.50%	0.75%								
CA	1.31%	1.26%	1.27%	1.28%	1.41%	0.92%	0.88%	0.90%	0.90%	0.91%	0.90%	0.89%
CO	0.53%	0.76%	0.80%	0.85%	0.90%	0.95%	1.00%	1.05%	1.10%	1.15%	1.20%	1.20%
CT	1.0%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%
DE	0.5%	0.8%	1.3%	2.5%	3.0%	3.0%	4.0%					
HI	0.6%	0.6%	0.8%	0.8%	1.0%	1.0%	1.3%	1.3%	1.5%	1.5%	1.8%	1.8%
IL	0.4%	0.6%	0.8%	1.0%	1.4%	1.8%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
IN		0.3%	0.5%	0.7%	0.9%	1.1%	1.3%	1.5%	1.7%	1.9%	2.0%	2.0%
IA	1.0%	1.2%	1.3%	1.4%	1.4%							
MD	1.0%	1.2%	1.7%	2.2%	2.7%	2.6%	3.1%					
MA	1.0%	1.5%	2.0%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%
MI	0.3%	0.5%	0.8%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
MN		1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%
NM		0.9%	0.9%	0.8%	0.8%	0.8%	0.6%	0.6%	0.6%	0.6%	0.8%	0.8%
NY	2.1%	2.1%	2.2%	2.2%	2.2%	2.2%	2.3%					
OH	0.3%	0.5%	0.7%	0.8%	0.9%	1.0%	1.0%	1.0%	1.0%	1.0%	2.0%	2.0%
PA			1.0%	1.0%	1.0%							
RI	1.2%	1.2%	1.1%									
TX	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
VT	2.6%	2.6%	2.6%									
WA	0.7%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
ENO	**0.1%**	**0.1%**	**0.1%**	**0.1%**	**0.2%**	**0.1%**	**0.2%**	**0.2%**	**0.2%**	**0.2%**	**0.0%**	**0.0%**

Targets have not been set for the years in grey.

Sources: "Advancing Energy Efficiency in Arkansas," M. Neubauer, et al., American Council for an Energy-Efficient Economy, June 2010, Table 14; AR savings from APSC Order 15 in Docket No. 08-137-U; ENO savings from 2009 ENO IRP, Figure ENOI-7; ENO sales from 2009 SRP, Figure 3.5 for 2009 and 2009 SRP Refresh, Figure A-3 for later years.

2 With Energy Smart, ENO's spending level would rise to about 0.2% or
3 0.3% for three years. By year three of Energy Smart (which would be roughly
4 2013), Entergy should aim to increase savings well above those of the current
5 Energy Smart plan. Savings should continue rising after the end of the current
6 plan.

7 The spending rate for the Energy Smart program is about $0.60 per MWh
8 of retail sales. The leading jurisdictions in energy efficiency have been spending
9 at least twice this much per unit of sales, and seven states spent more than four
10 times as much in 2009. While the purpose of energy-efficiency programs is to

save energy, not spend money, it is likely that Entergy will need to spend considerably more than the Energy Smart budget to bring its New Orleans programs to the top echelon nationally.

Q: What are the benefits of energy-efficiency programs?

A: The benefits of energy-efficiency programs include

- the avoided costs listed in Section IV.A, page 13, below;
- reduced price volatility and risk associated with fuel costs, costs of building new units, and performance of existing generation;
- avoiding or deferring the need for expensive new generation, transmission, and distribution projects, with their front-loaded cost recovery;[5]
- increased local employment and spending on implementing energy efficiency;[6]
- increased local economic activity due to the reduction in bills and additional disposable income for New Orleans residents and businesses;
- increased competitiveness of New Orleans for industrial firms and commercial enterprises;
- reduced air and water pollution, locally and upstream along the Mississippi and its tributaries;
- reduced global-warming emissions.[7]

---

[5]As I describe in Section VI, it is not clear that ENO requires 100 MW of combined-cycle capacity in 2015, or that ELL requires 400 MW of combined-cycle capacity in 2015. If they do require that capacity with Entergy's forecast load, energy-efficiency should reduce that need.

[6]Most of the costs of generation resources are for fuel, equipment purchases, interest, and dividends, all of which primarily flow out of New Orleans. Most energy-efficiency programs, in contrast, require large amounts of local labor, which cannot be outsourced, as well as local retail purchases.

[7]Given New Orleans's vulnerability to higher sea level, as well as more frequent storms, the City's efforts to reduce global warming have a strong symbolic significance.

Q: Do these benefits accrue solely to participants in the energy-efficiency programs?

A: No. Customers who do not participate in the programs also benefit in many ways.

One set of benefits flows through rates. Energy-efficiency avoids the use of the most expensive energy source that would have been dispatched for ENO (or ELL) in any particular hour. Since that marginal cost exceeds the average dispatch cost in the same hour, energy efficiency reduces the average fuel and purchased-power cost, benefiting all customers. Since much of that marginal supply is fired by gas, with its high price volatility, energy-efficiency also reduces the volatility of energy bills. Non-participants also benefit through rates from the avoidance of new supply construction, with its front-loaded cost recovery.

A second set of benefits—all of the economic and environmental benefits listed above—flow to non-participants as well as participants.

A third set of benefits for non-participants is related directly to energy efficiency. If the Council commits to long-term comprehensive energy-efficiency efforts, most of the non-participants in the first years' programs are likely to benefit directly from the programs in later years, when they get around to participating in retrofit programs; build, buy or rent a new (or remodeled) building made more efficient by the new-construction programs; or replace equipment (e.g., air conditioners, heat pumps, water heaters, appliances) eligible for efficiency incentives. As energy-efficiency programs change the standard practice of architects, engineers, HVAC contractors, and builders, and change the mix of equipment stocked by distributors and retailers, even customers who never receive a program rebate or discount are likely to benefit from more efficient equipment and buildings.

IV. Energy-Efficiency Screening

Q: What energy-efficiency-screening issues do you address?

A: I deal with two topics: the avoided costs that constitute the bulk of direct benefits from energy-efficiency programs, and the cost-effectiveness tests used in screening energy-efficiency programs and measures.

A. Avoided Costs

Q: Please summarize the items that should be included in avoided costs for energy-efficiency screening.

A: The electric utility avoided costs comprise generation, transmission-and-distribution capacity, and generation energy. Avoided generation capacity costs should include a reserve margin, since reliably serving each kilowatt of peak load requires more than a kilowatt at the generation level, to allow for plant outages. Both capacity and energy avoided costs should also reflect marginal line losses between the generator and the end use.

Since electric-energy efficiency programs will usually affect gas usage, program screening should include avoided gas costs. For example, sealing ductwork will save air-conditioning energy and also heating energy; the same is true for building insulation and reduction in air leakage.[8] Avoided gas costs include wholesale gas prices delivered to the city gate for normal weather, plus the reserve pipeline and/or storage capacity maintained by ENO to cover loads under design weather conditions. In many cases, lower load growth also avoids costs of expanding the distribution system.

---

[8]Some electric-energy efficiency measures, such as efficient lighting, will slightly increase winter gas use in gas-heated buildings.

Many energy-efficiency measures reduce usage of hot water, and hence water consumption. That saved water should be valued at the marginal cost of water supply, which is often considerably in excess of embedded-cost rates.

Ideally, avoided costs will include the environmental benefits of reduced usage of energy and water. Given the rudimentary level of energy-efficiency in New Orleans, incorporation of environmental costs, beyond those included in direct costs through allowance trading and similar mechanisms, is probably not a good use of the Council's attention at this time. Nonetheless, the Council should be cognizant of the environmental benefits in its review of program budgets and goals.

Q: How should avoided costs be computed for DSM-program screening?

A: Since both the electric and gas industries operate in a largely competitive wholesale market, the most straightforward approach to projecting wholesale avoided costs is to use projections of market prices.[9] These costs must be adjusted to reflect the shape of retail load, and to include other delivery costs.

Q: Should avoided costs vary significantly among the Entergy operating utilities?

A: Not for the wholesale components of cost. All the Entergy utilities face essentially the same cost for acquiring more energy (either producing it at marginal costs or purchasing it from other generators), the same market prices for the sale of energy freed up by energy-efficiency programs, and the same market options for purchasing and selling capacity. Hence, avoided generation

[9]The utilities should not be procuring or retaining resources with avoidable costs greater than market prices. A utility may believe some resource is cost-effective, even though it is priced above market, due to the security of supply or other factors. If the Commission agrees, the factors causing that extra value should also be added to the costs avoided by energy efficiency.

costs should be very similar across the Entergy system. There may be some differences in avoided energy costs due to variation in transmission line losses and congestion among the Entergy zones.

Line losses within the various Entergy companies may also differ, as may avoided transmission and distribution costs.

Q: Have you reviewed Entergy's estimates of avoided costs?

A: I have reviewed the information available in the ICF potential study, at pages 2-14 through 2-15; and in Section X and Appendix 7 of ENO's Energy Smart report of July 2, 2009. My concerns about these avoided costs are as follows:

- There is no indication that ENO included any value for the amount of gas saved by the electric energy-efficiency measures it modeled.[10]
- The generation capacity cost appears to be based on the cost of a peaking combustion turbine, at $680/kW in 2008 dollars. This cost appears to be at the low end of the costs of recently constructed combustion turbines, many of which have cost close to $1,000/kW.
- More troublesome, the avoided capacity cost reflects only the cost of a combustion turbine, while Entergy is actually planning on adding more expensive combined-cycle units, and it is those combined-cycle units that would be avoided by energy-efficiency, not new combustion turbines. You can't avoid what you are not planning in the first place. The additional cost of the combined-cycle plants is incurred to lower energy costs, and should be reflected in the avoided energy costs; Entergy has not indicated whether the avoided energy costs include the excess costs of the combined-cycle capacity.

---

[10]Appendix 6 to the Energy Smart report does indicate that ENO had estimates of the therm savings.

- The losses reported in Appendix 7 to the Energy Smart report (p. 14), appear to be average annual energy losses. But percentage losses vary with load. Losses at peak, applicable to capacity, are typically considerably greater than average annual energy losses. Average energy losses in the peak period exceed annual average losses, and average losses off-peak are less than average. More importantly, the marginal losses avoided by reductions in load are twice the average line losses. Hence, it appears that Entergy has understated losses for capacity, on-peak energy, and off-peak energy.
- Entergy reports different losses by customer class. Those differences are probably due to the fact that power delivered to a portion of larger customers is metered at primary distribution voltage or even transmission, rather than at the lower secondary voltage at which residential customers are metered. This distinction is appropriate for cost-of-service studies or rate design. However, almost all electric energy is actually used at the secondary level, and the same losses occur in the transformers and lines, whether they are on Entergy's side of the meter (for residential and most commercial customers) or on the customer's (for many industrial customers). Hence, losses to secondary should be added to all end-use energy savings.
- The avoided transmission and capacity cost of $2.93/kW-year is far less than any such estimate I have ever seen derived from actual or projected investments per kilowatt of load growth. The only description of the derivation of the avoided transmission and capacity cost—in Appendix 7 to the Energy Smart report (p. 15)—is too vague and sketchy to review in

detail, and does not actually produce the $2.93/kW-year used.[11] It appears Entergy assumed that of all its distribution equipment, load reductions could avoid only 30% of the costs of reconductoring projects (or about 5% of what Entergy calls "planned" distribution investment) and 5% of distribution transformer upgrades, excluding a wide range of load-related upgrades and load-related equipment failures. Appendix 7 is also not clear as to what parts of the analysis were undertaken for ENO, ELL, or the entire Entergy system.[12]

- The avoided costs include a reserve margin of 16.8%. Entergy projects that ENO and ELL would need reserves of 18% in 2014–15 and 20% after 2015, due to changes in contractual relationships among the Entergy utilities (ENO IRP, pp. 4–5). While I am not convinced that the contractual changes will affect reliability or reserves (see Section VI), if Entergy really proposes to plan for a 20% reserve margin, that should be reflected in the avoided costs.

Q: How should avoided costs for New Orleans be estimated?

A: The Council should require that the avoided costs be developed in an entirely public process and thoroughly documented. Entergy could work directly with Council Advisors, the Alliance, and other interested and knowledgeable parties to develop a consensus set of avoided costs for energy-efficiency screening.

Q: Please describe the derivation of avoided electric generation costs.

---

[11] Appendix 7 produces an avoidable investment in annual dollars over 2013–2017. Entergy does not specify the load reductions that would produce those reductions, or how these avoided annual investments are converted to dollars per kilowatt-year.

[12] By transformer upgrades, Entergy appears to be referring to substation transformers.

A: Avoided generation energy costs can be estimated starting with brokers' quotes (or supplier offers) for forward energy or with the results of market-oriented production-cost models. Since forward quotes for energy delivered in the Entergy system appear to be available only a couple years into the future, they provide only a starting point for avoided costs, and a check on production cost models. Those models will need to reflect demand and supply conditions in the SPP, the Entergy system, and at least parts of SERC (e.g., the TVA and Southern Company), MISO and the Midwestern parts of PJM.

Modeling of energy costs should include the costs of tradable emissions permits, including reasonable projections of the price of carbon emissions, which Entergy appears to reflect. Production-costing models should reflect the increases in variable operation-and-maintenance (O&M) costs, increases in heat rate, and reductions in capacity resulting from pending and future environmental retrofits for existing generation. Entergy has not provided details of its avoided-cost modeling.

Forward contract prices are stated for flat blocks of power, such as 50 MWh per hour for all hours in a month, or for all on-peak hours. Actual retail energy usage (and average energy-efficiency savings) has a very different time pattern. In particular, when loads are high (due to hot summer or cold winter temperatures), prices tend to be high, so the value of the average kWh used or saved is more than that of the average kWh in the flat wholesale power blocks. The additional value of the load-shaped energy can be estimated by comparing the load-weighted to hour-weighted average prices from market values (if available), system lambda data, or production-cost modeling results. Entergy does not state whether it recognizes load shape in its computation of avoided costs.

For screening purposes, avoided energy costs are usually differentiated by seasonal periods (typically summer to recognize the higher loads, winter to recognize higher fuel costs, and spring/fall) and time of use. The savings from each measure or program are then characterized by season and time of use. Entergy estimates avoided energy costs for on and off-peak periods, and apparently for each month (since it provides estimates specifically for July 2035); it is not clear what level of detail is used in characterizing measures, or how the avoided costs are aggregated to match that level of detail.

In addition to wholesale energy, energy-efficiency avoids some capacity costs. In the long term, the capacity cost is generally derived from the real-levelized capital and operating cost of new peaking capacity.[13] In the shorter term, the value of reduced capacity requirements can be determined from recent wholesale peaking capacity transactions or from the costs of keeping older peaking units (combustion turbines or old gas boiler plants) on line. In any case, the avoided cost per kW-year of capacity should be increased by the required reserve margin to determine the avoided capacity cost per kilowatt of demand reduction.

Q: What costs must be added to wholesale electric generation prices to develop full avoided electric costs?

A: There are two categories of costs below the wholesale level. First, marginal losses must be added to the generation costs. Since line losses increase with the square of the current flowing through the line, marginal line losses tend to be

[13]Entergy is planning to add more-expensive gas combined-cycle intermediate capacity, but the additional cost of that capacity should be covered by its energy savings compared to a peaker. If the additional capital cost is not entirely offset by energy savings over its life, the combined-cycle capacity will not usually be justified. In any case, the net incremental combined-cycle cost should be included in avoided energy costs.

1 twice the average variable losses, and the losses (marginal or average) tend to be
2 greater in high-load hours than in low-load hours, and greatest at the system
3 peak. Marginal line losses for various time periods can be modeled with fairly
4 complicated models, or simply scaled from the annual average losses.[14] Regard-
5 less of where the customer's load is metered, almost all energy is consumed at
6 distribution voltage, so avoided costs should reflect losses to the distribution
7 level, which need not vary among classes.

8 Second, reducing loads will tend to reduce the need for new transmission-
9 and-distribution capacity. Avoided T&D investment per kilowatt are usually
10 estimated by taking the additions in each year (net of retirements, grossed up to
11 reflect inflation from the installation date of the average dollar of retired
12 equipment), inflating several years' data to a common year, and dividing by load
13 growth in that period. That capital cost is then annualized with a real carrying
14 charge (reflecting return, depreciation, and taxes) and adding O&M.

15 **Q: Please describe the derivation of avoided gas commodity costs.**

16 A: Wholesale forward monthly contracts for gas at Henry Hub are actively traded
17 about five years out; those prices provide a market-based projection of the
18 wholesale price of gas. Further out, escalation in gas prices should be based on
19 forecasts, such as the Energy Information Administration's Annual Energy
20 Outlook. The Henry Hub price is likely to be very close to the price at the New
21 Orleans city gate.

---

[14]Reported losses (e.g., in the FERC Form 1, p. 401a, line 27) are generally computed by comparing sales to generation energy for the year. Sales in 2009 include energy generated in December 2008 but not metered and billed until January 2009, and some energy generated in December 2009 is not recorded as sales until January 2010. Hence, the reported losses should be averaged over several years.

Gas avoided costs are usually computed by end use (typically baseload, space heating, and water heating), rather than time period. Annual baseload avoided costs are simply the average prices across the months, weighted by the number of days in the month. Annual space-heating avoided costs are greater than baseload because more of the energy is used in the high-price winter months, and because sales within each month are higher on days with higher loads, when market prices are also likely to be higher. The market price for each month should be adjusted upward by the historical ratio of the daily prices weighted by heating load (or heating degree-days, as a proxy for heating load), and the resulting prices should be averaged across months, weighted by normal monthly heating load (or degree-days).

Water-heating loads are intermediate in shape between baseload and space heating; while customers use hot water in every month, usage of hot water, and standby and distribution losses rise in cold weather. Avoided costs for water heating can be estimated like those for space heating (if data are available on water-heating usage patterns), or as a weighted average of baseload and space heating avoided costs.

Q: What costs must be added to wholesale gas prices to develop full avoided gas costs?

A: In addition to meeting normal loads, gas utilities must have sufficient reserve capacity to meet loads on the design day, and in design-basis cold spells. That reserve may be in the form of pipeline capacity, underground storage capacity, compressed or liquefied gas storage, or propane storage and injection capacity. Avoided cost for each weather-sensitive load shape should include the cost of reserve capacity for the difference between design and normal loads, divided by the normal annual gas usage.

Losses in the gas-delivery system do not appear to be significantly related to throughput, and thus are not usually avoidable by energy-efficiency programs. Some systems have costs that do vary with load, such as energy for compression; those should be included in avoided costs.

Finally, avoided load-related transmission and-distribution-costs should be estimated for gas as they are for electricity.

B. Screening Tests

Q: How should energy-efficiency measures and programs be screened for cost-effectiveness?

A: The determination of whether measures, measure enhancements, and programs are beneficial should be based on the Total Resource Cost (TRC) test, which includes all costs and benefits to utility customers (whether those flow through utility bills or are otherwise borne by customers) or the Societal test, which also includes a broader set of costs and benefits, specifically environmental emissions.

The TRC and Societal tests do not recognize incentives paid to program participants as either a cost or a benefit, since the dollars are simply being moved among customers.[15] The Program Administrator Cost (PAC) test (which was known as the Utility test when utilities ran all ratepayer-funded efficiency programs) compares the cost to the utility system (incentives and program costs) to the system benefits (avoided costs). The PAC test is used primarily to set a cap on incentives payments, once the other aspects of the program have been

[15]In this regard, program incentives are much like the direct effects of rate design or cost allocation among rate schedules; every dollar shifted benefits some customers and is paid for by other customers.

1 designed to maximize the net TRC benefits. If the incentives necessary to
2 maximize TRC benefits would cause a program to fail the PAC, the parties need
3 to think carefully through the tradeoffs and justify the recommended program
4 design to the Council.

5 **Q: Are there any complications in applying these tests?**

6 A: It is important to include realistic avoided costs and other inputs in the
7 screening. In particular, the TRC benefits of electric-oriented energy-efficiency
8 programs should include the avoided costs of natural gas and water, as well as
9 customer savings from reduced operating and maintenance costs (e.g., avoided
10 replacement of incandescent lights where longer-loved CFLs or LEDs are
11 installed) or delayed equipment replacement.[16]

12 In some cases, it is important to consider the costs and benefits of multiple
13 measures as a bundle. For example, reducing lighting, infiltration, insolation
14 (sunshine), and other heat loads in a building, and sealing the duct so they do
15 not leak cold air into the hot attic, may allow the downsizing of the air
16 conditioner when it is replaced with a more efficient unit. Coordinating the
17 measures saves on the costs of the replacement air conditioner, reduces fan
18 energy usage (since the fans are no longer blowing cold air into the attic and
19 through leaky walls), and allows the house to stay uniformly comfortable with
20 less energy use, since the oversized air conditioner would have been cycling on
21 and off, allowing humidity to rise, encouraging the occupants to turn down the
22 thermostat in an attempt to be comfortable. Similarly, the cost of getting an
23 installation team into a residential or small-commercial building will only be
24 justified if it is spread over a wide range of measures.

---

[16]Similarly, the PAC test should include avoided gas costs.

A more complicated set of considerations arise in trying to define all the benefits of energy-efficiency investments. For example, replacing leaky decrepit windows with tight windows that keep summer heat out and winter heat in saves energy but also provides the following benefits:

- improving comfort,
- providing better appearance (depending on how much the existing windows are rotten, corroded, peeling, and/or flaking),
- improving safety (e.g., by removing lead paint and the risk of a double-hung sash falling on an unwary finger),
- reducing maintenance,
- increasing functionality (replacement windows often open and close more easily),
- increasing convenience (many replacement windows rotate into the room for washing).

Clearly, these benefits will be worth something to many program participants, who would pay for those benefits. Determining the dollar value of those benefits can be difficult. In some cases, the program can be screened and incentives set based on the cost of a basic-level replacement; a customer who chooses to spend more for fancier windows or a high-end efficient refrigerator is making the decision that the additional benefits are worth the additional cost, and bears that increment of cost. In other cases, even the most basic version of the measure will provide many of these benefits. If the measure does not screen without valuation of benefits fore which customers appear willing to pay, some additional research may be needed to value the benefits.

Q: What is the appropriate role of rate effects in the screening of energy-efficiency measures and programs?

A: Rate effects should not be considered in the screening of energy-efficiency measures and programs. Whether the effects of the energy-efficiency portfolio on the rates and bills of any class for any particular year requires a comprehensive analysis of the entire portfolio over time, reflecting the avoidance of expenses and investments (for generation and transmission-and-distribution), the allocation of costs among classes, and the timing of energy-efficiency cost recovery. If a problem appears in this analysis, the solution may involve redistributing the emphasis of the energy-efficiency programs or the allocation of costs, or amortizing some energy-efficiency costs over time.

V. Cost Recovery for Energy-Efficiency Programs

Q: What rate items should the Council should consider allowing Entergy to recover from ratepayers?

A: Entergy might be entitled to the following kinds of rate items:

- Entergy's expenditures for energy-efficiency incentives, measures, installation and program overheads;
- the reduction in revenues in excess of Entergy's short-term savings, the "lost contribution to fixed costs" or "lost revenues;"
- incentives to Entergy for superior performance in delivering energy-efficiency services to its customers.

A. Program Costs

Q: How should the Council allow Entergy to recover its expenditures on energy-efficiency programs?

A: Many jurisdictions allow the recovery of energy-efficiency expenditures through periodic (often annual) adjustments though an energy-efficiency rider. While

1 review of the utility's performance must be included in the cost-recovery
2 process, the review can be streamlined if Entergy is implementing programs
3 designed and evaluated under collaborative supervision.

4 To avoid conflict among customer classes, it is often advisable to allocate
5 the costs of each program to the class (or classes) of the program participants.
6 The major exceptions to this rule would be for low-income programs, which
7 should be recovered from all other customers.

8 ***B. Lost Revenues***

9 **Q: What is the purpose of computing the lost contributions to fixed costs**
10 **resulting from utility energy-efficiency programs?**

11 A: The principal purpose of energy-efficiency programs is to reduce costs to
12 customers, including costs that flow through utility bills. For electric utilities,
13 those costs include fuel, variable O&M, net purchased power, and new genera-
14 tion, transmission, and distribution investments. For gas utilities, the avoided
15 costs include purchased gas, transportation and storage contracts, and local
16 storage, transmission, and distribution investments.

17 When load is reduced, or grows more slowly, the utility's revenues are less
18 than they would have been otherwise, and so are the utility's costs. In the short
19 term, an electric utility saves on fuel, variable O&M, and net purchased power
20 (either by purchasing less or selling more energy and capacity); a gas utility
21 saves on purchased gas and some transportation and storage costs.[17] These
22 short-term savings are generally less than the reduction in revenues, leaving the
23 utility with lower earnings until rates are reset in the next general rate

[17]Most of these costs (fuel, purchased power, purchased gas) are reconciled through fuel-adjustments and gas-supply rates, so the reductions in utility costs and revenues are equal.

proceeding. In the longer term, reduced load saves on generation, transmission, and distribution capacity costs, but those savings primarily flow to customers through lower rates.

Under these conditions, every kWh that a customer does not use due to an energy-efficiency program reduces the utility's earnings. As a result, the utility has a financial incentive to delay implementation of DSM, especially measures that have particularly large effects on revenue.

Q: What approaches are generally used for recovery of lost revenues?

A: The three principal approaches are as follows:

- *Projection of DSM-program effects* in estimating sales and setting rates in general rate proceedings. These are the full-year effects of measures installed prior to the rate year (both preceding the rate filing and during the rate proceeding), plus partial-year effects of measures installed during the rate year. This approach is most effective if rate proceedings are filed every year, and may have difficulties dealing with situations in which projections of installations turn out to be dramatically wrong. Projection of DSM program effects can be combined with either of the other two approaches.
- *After-the-fact computation of lost revenues,* from the count of measures installed the estimated savings per measure, and the lost revenues per kWh or ccf.[18] The establishment of a lost-revenue mechanism is conceptually simple, but dependent on many details of tracking the number of installations and estimating their effect on sales and revenues. Lost-revenue mechanisms were more-widely employed in the 1990s, but have been replaced with decoupling (below) in several jurisdictions.

[18]Entergy has proposed this approach in its current rate case, Docket No. 09-084-U.

- *Decoupling of revenues from sales,* by setting a revenue target, reconciling actual revenues to that target, and returning the difference to the customers or utility (depending on whether the utility over- or under-collects the revenue target). Decoupling, or rate stabilization, does not usually distinguish among the causes of these revenue deviations. Unlike lost-revenue mechanisms, decoupling mechanisms are generally straightforward to operate, but great care must be taken in the details of mechanism design, to avoid inadvertent windfalls to the utility and to share reasonably the risks of economic downturns.

Q: How do computations of lost revenues typically work?

A: The basic approach in computing lost revenues comprises the following steps, for each measure covered by an energy-efficiency program:

1. *Count the number of measures installed under the program.* An effective and accurate tracking system is essential for this determination.
2. *Estimate the annual sales effects of each measure.* This step requires that the tracking mechanism must report more than the number of installations; the sales reduction will depend on the size and efficiency of the installed equipment, hours of operation (which depends on business type and location of the measure), and other data.
3. *Estimate the percentage of the savings that would have occurred without the program,* and that thus do not reflect any program-related revenue loss. This step is dependent on high-quality evaluation.[19]

[19]The participants who would have invested in efficiency without the program are often called "free riders." That terminology incorrectly suggests that they are somehow getting a better deal than other participants.

4. *Estimate the extent of spillover from the program to non-participants.*[20] Again, this is a function of evaluation.

5. From the tracking mechanism, *determine the types of customers participating in the program,* differentiated by rate schedule and by any other factors that affect lost revenues per kWh or ccf saved.

6. *Compute when the savings from each measure would start,* given both the installation schedule (from the tracking system) and any seasonality of the affected load (e.g., space-heating efficiency measures installed in May do not save much energy until the following November).[21]

7. *Determine the lost contribution to fixed charges,* per kWh or ccf, for each group of customers. This computation requires determination of the customer's bill reduction per kWh or ccf saved, net of any short-run savings to the utility and net of any costs that will be reallocated through reconciliation mechanisms.[22]

8. *Compute the resulting lost contribution to fixed cost* as the product of the energy savings and the lost contribution per kWh or ccf, by class.

Q: What problems arise if the lost revenues are poorly estimated?

---

[20]Examples of spillover would include installations that occur because engineers, architects and contractors come to habitually specify efficient equipment, or because efficient equipment becomes the standard equipment stocked in warehouses and stores and is hence easier to find and less expensive than inefficient equipment.

[21]Seasonal rates and seasonal differences in the coincidence of measure load with customer billing demands may cause lost contribution per unit of sales to vary with the date of installation and the date on which rates are reset in the next rate case.

[22]For example, demand charges may or may not be reduced by reduced sales, especially if the tariff includes contract demands and/or demand ratchets. In classes with block rates, lost revenues should reflect the percentage of participants with marginal usage in each block. Effective rates may also vary among measures due to differences in time-of-use and seasonal patterns.

1 A: Erroneous estimate of lost margins produce problems with fairness, incentives,
2 and gaming. The fairness problem arises because the utility may get much more
3 (or less) back in lost revenues than it actually loses, and customers pay much
4 less (or more) for fixed costs than without the DSM program.

5 The problem of incentives is even more serious than that of fairness. If the
6 utility realizes that it will be overpaid for some installations, and underpaid for
7 other installations, it will have an incentive to encourage participation by
8 customers in the first group and discourage participation by customers in the
9 second. If lost-revenue recovery for a particular measure is apt to be less than
10 the actual lost revenues, the utility would have an incentive to discourage
11 implementation of that measure, perhaps by imposing additional administrative
12 burdens or reducing rebates.

13 The gaming problem is very similar to the incentive problem, but with a
14 more active utility role. If the utility anticipates that it will be overpaid for some
15 installations, and underpaid for other installations, it will have an incentive to
16 steer the programs to the most-profitable installations. For example, the utility
17 might promote a program heavily to customers with small installations, small
18 savings, and/or lower lost revenue per unit of savings, but claim higher lost
19 margins based on average savings and average revenues for some broader group
20 of potential participants.

21 **Q: How would a revenue-stabilization mechanism operate?**

22 A: A revenue-stabilization, or decoupling, mechanism would compare actual re-
23 venues to a target revenue level, and adjust rates to flow the difference to the
24 utility or its customers.[23]

---

[23]Revenue decoupling is a simpler variant of the return-on-equity adjustment proposed by Entergy in its current rate case, Docket No. 09-084-U.

Q: Would a revenue-stabilization mechanism have any advantages compared to a lost-revenue mechanism?

A: Yes, at least three. First, a revenue-stabilization mechanism would eliminate any weather-related over- and under-collections, stabilizing bills for customers and revenues for Entergy. After a particularly hot summer or cold winter, when electric bills have strained customers' budgets, customers would receive rate reductions offsetting the non-fuel part of the increased cost. After particularly mild weather, when customer bills and utility earnings would tend to be lower than normal, customers would give up some of those benefits and Entergy earnings would rise toward normal.

Second, the projection of sales in a rate proceeding would no longer be of great import. Were the forecast overstated, the revenue-stabilization charge would increase; if understated, the charge would decrease and perhaps even become negative. Reducing the weight of the sales forecast in rate proceedings should reduce the cost and burden for Entergy, the Council Advisors, and other parties.

Third, lost-revenue adjustments also generally cannot account for savings resulting from the utility's role in encouraging or supporting efforts by other parties, where measuring the savings or allocating a specific share of savings to the utility would be difficult. Examples if this activity include providing information and other indirect support for energy-efficiency investments, as well as the effects of market-transformation efforts, governmental codes and standards, and other programs (such as those operated by the Louisiana Department of Natural Resources). A revenue-stabilization mechanism does not differentiate among the possible reasons for differences between target and actual revenues, and hence would protect utility revenues from the effect of all sorts of efficiency programs, regardless of who administers those programs.

Q: Would a revenue-decoupling mechanism have any disadvantage compared to a lost-revenue mechanism?

A: The major potential disadvantage of a revenue-decoupling mechanism is that, unless otherwise specified, it trues up revenues for all variations in sales, including economic cycles. Thus, in an economic downturn, a revenue-decoupling mechanism would protect the utility shareholders from economic conditions, when almost everyone else—households, businesses, state and local governments—is suffering.[24] This would often be viewed as unfair. Hence, some modification of decoupling in the event of serious economic disruption is probably justified.

Decoupling mechanisms also frequently have features that attempt to track legitimate cost drivers, such as the addition of new customers. These adjustments to the allowed revenue level must be thought through carefully, to avoid giving Entergy an incentive to manipulate the adjustment or inadvertently creating windfalls or losses.

Q: Would the savings estimates used in screening programs be appropriate for estimating the sales reductions in Step 2 of lost-revenue determination?

A: Not in all cases. The initial savings estimates (often called "deemed savings") are tools for screening and planning, and may be reasonable sources of forecasts for lost revenues. In many cases the initial estimates will not be the best estimate of savings after the fact. The Arkansas PSC has recently articulated the following standard for recovery of lost revenues:

[24]Entergy's proposed true-up for return on equity would have a similar effect.

> LCFC calculation shall accurately reflect energy savings caused by utility energy efficiency programs.... Utilities shall maintain and report adequate data to support accurate calculation of revenues lost. ... EM&V reflecting standard protocols and best practices in the EM&V profession shall be preferred over deemed savings where such EM&V is available. Utilities shall base LCFC applications and calculations on the best information available at the time of the application. (Docket No. 08-137-U, Order No. 14, December 10, 2010, p. 19)

Initial-savings estimates are often stated per application (per house, per commercial customer, per appliance replaced). They are based on guesses borrowed from other jurisdictions (with different energy prices, building codes, climates, and DSM incentives) regarding the size of the equipment installed, the size of the load (e.g., the house, room, or building receiving the measure), the pre-DSM efficiency and the post-DSM efficiency, annual hours of use, and other factors. The average installation may differ from the basis of the deemed saving by involving more or fewer hours of use annually, square feet of insulation, tons of cooling controlled, or many other factors.

The standard for estimating savings for lost-revenue recovery should be the best information available at the time the utility files for cost recovery. That information may be the same as the deemed savings, but should also reflect data available from the installation-tracking process and any other new information. The resulting recovery may be more or less than would been computed from the deemed savings. This important point is that the lost-revenue recovery should recover actual lost contribution to fixed costs.

Q: Is it more important that savings estimates be accurate for program design or for lost-revenue recovery?

A: Accuracy is much more important in lost-revenue recovery. In many cases, changing the assumed savings of a measure by a considerable margin would make no difference in program design. A measure with a benefit-cost ratio of 3.0

will remain cost-effective even were the estimate of its savings found to be overstated or understated by 100%. For lost-revenue recovery, that same error of estimating savings at twice their actual value would result in a public utility recovering twice its lost revenues, potentially millions of dollars across a DSM portfolio.

Q: What actions are necessary to ensure availability of the information needed to estimate actual lost contribution to fixed costs?

A: For the lost-revenue mechanism to be effective, the tracking mechanism must record all the information necessary to estimate the incremental savings attributable to the DSM programs, such as equipment size, existing equipment status, building size, and hours of use, and the information necessary to determine participation by rate schedule. In addition, monitoring, verification, and evaluation efforts must be sufficient to test and correct a range of other assumptions about the effectiveness of various measures and their interactions. Most of these efforts are important for other purposes—load forecasting, cost-effectiveness determination, improved program design—so the incremental costs of monitoring, verification, and evaluation to support lost-revenue recovery should not be substantial.[25]

For each rate schedule, lost revenues should be estimated for each type of measure. At a minimum, that computation should include at least heating, cooling, and baseload measures. Depending on the rate schedule (and the DSM measures applicable to the customers on that schedule), it may be appropriate to distinguish further among measures (e.g., economizers, outdoor lighting) or

[25]Due to the utility's strong self-interest in the monitoring, verification, and evaluation process, that process should be directed by collaboration among Entergy, the Council Advisors, the Alliance, and other consumer interests.

1 subsets of customers on the rate schedule (e.g., customers with their usage
2 entirely in the first block).

3 ## *C. Incentives*

4 ### *1. The Purpose of Shareholder Incentives for Demand-Side Management*

5 **Q: Are shareholder incentives required to make shareholders whole for the**
6 **effects of DSM?**

7 A: No. Lost-revenue recovery or decoupling would make shareholders whole for
8 the revenue reduction from DSM.

9 Utilities sometimes argue that shareholders are harmed by the loss of the
10 opportunity to invest in supply that is no longer needed due to energy efficiency.

11 This is an entirely specious argument. If the Council sets a utility's allowed
12 return on equity at the cost of equity, shareholders should be indifferent between
13 investing more in that particular utility and putting their money in other
14 investments of equivalent risk. Shareholders are harmed by reduction in the
15 utility's capital requirement only if the allowed return exceeds the cost of
16 capital, in which case the Council should reduce the allowed return.

17 The utilities would earn exactly the same return on an *investment* in energy
18 efficiency as they do for traditional investments in generation, transmission,
19 storage or distribution. However, utilities usually invest very little in energy
20 efficiency; almost all of the costs are expensed and recovered quite quickly.
21 Hence, there is no asymmetry in the treatment of DSM and supply under tradi-
22 tional ratemaking. Utilities do not earn a return on any expenses: fuel, purchased
23 power, labor, purchased services or DSM.

24 **Q: Is there a justification for shareholder incentives?**

A: Yes. While not justified to maintain a return to shareholders, incentives may be necessary to promote real and sometimes difficult shifts in organizational culture and practice. For instance, utilities may resist aggressive utility investment in DSM due to inertia, distraction by more-traditional organizational priorities, lack of positive experience with aggressive DSM, inadequate expertise, and even a perception that it energy efficiency may conflict with legitimate corporate goals.

Senior utility management is more familiar with supply planning than with demand planning, and supply advocates tend to be more powerful within the organization than are the demand-side advocates. Many senior managers spent much of their careers in the traditional supply functions of the utility—power-plant construction and operation, power and gas purchasing, transmission and distribution planning—and related financial operations, and may be more interested in those activities than building a center of excellence in DSM. Staff members who have spent their entire lives encouraging the use of energy may have difficulty adapting to a policy of discouraging its use.

In particular, utilities are used to evaluating their performance and competitiveness by tracking rates in cents per kWh or ccf; employees with that perspective may have a hard time believing that DSM (even with favorable recovery of costs and lost revenues) will not harm their company.[26]

In addition, utility management may prefer higher sales, since a larger and faster-growing company is more exciting to manage. The growing company will present more opportunities for hiring and promoting staff, making dramatic decisions about expansion projects, and being feted by investment banks and

[26]Some utility managers may also believe that DSM harms shareholders, and hence their own prospects. This is yet another barrier to DSM implementation.

equipment suppliers. For particular groups within utility management, such as power-plant and transmission planners, the reduction in the need for and importance of their services may be threatening.

It is this combination of inertia and the very real self-interest of utility management that creates the need for some incentive to overcome internal resistance to energy efficiency. Even if the lost-revenue mechanism or decoupling would create a level playing field in objective financial terms, an explicit incentive might be necessary to balance the inertia of history and managerial psychology.

2. Incentive Structure

Q: How might a shareholder incentive be structured?

A: One relatively simple approach to shifting corporate culture towards implementation of energy-efficiency resources that has been used in many jurisdictions has been to offer utilities a share of the savings of the net benefits resulting from their energy-efficiency programs.

The net benefits should include all the cost categories used in program screening, including Council-approved avoided costs, utility program and measure costs, and participant costs.

Incentive computations should use the best information available at the time the utility is implementing the program.[27] The purpose of the incentive is to encourage the utility to strive to do more of the things that are identified as contributing to the objectives set out by the Council. For the incentive to be

[27]These may not be the best estimates at the time of cost recovery, which would be used in computing lost revenues.

1 effective, and not frustrate or confuse utility management, the utility must have a
2 clear idea of the incentives related to various levels of activity. If a particular
3 measure appears to have net benefits of $500 per installation at the time that the
4 utility is committing to the installations, the utility should be able to count on
5 that value in estimating the incentive it will earn. Changing the assumptions
6 after the fact is likely to give inconsistent signals and undermine the relationship
7 between achievements and rewards.

8 Management should implement the DSM plan on the basis of the best
9 available information from time to time during the plan implementation period.
10 As soon as new information becomes available, the incentives for future com-
11 mitments should be based on the improved information, and the utility (working
12 with other interested parties) should determine whether any modifications to the
13 program are appropriate.

14 Nor should Entergy be allowed to insulate itself from new information.
15 There must be mechanisms—a vigorous consultative process with an inde-
16 pendent evaluation function would be perfect—for stakeholders to provide the
17 utility with evidence that an assumption is wrong. The utility should retain the
18 responsibility for determining how to review the evidence and whether to
19 change its assumptions. If the utility does not respond appropriately to the
20 evidence (seriously reviewing it and revising assumptions as appropriate), it
21 should be at risk for disallowance of incentives that depend on the unexamined
22 assumptions. In addition, the utility should be at risk for expenditures that
23 appeared to be cost-effective with the utility's inputs, but not with ex-post-facto
24 estimates that correspond to the ignored suggestions.

25 **Q: Should the incentive be a fixed fraction of program net benefits?**

A: No. Incentives should reward exemplary performance. Incentives should thus start once the utility has achieved a substantial amount of savings or benefits. That threshold should be based on what other utilities have achieved, taking into account the ramp-up required to get to full DSM implementation. In various states, these thresholds have been set at 70% to 100% of savings targets.

Q: Should the incentive mechanism provide for penalties as well?

A: Yes. Entergy should also be exposed to penalties for performance that fails to meet a minimal standard, which may be lower than the threshold for earning incentives. Again, the appropriate penalty threshold and penalty rate should be set to be consistent with the goals and targets.

Q: Once the utility's performance reaches the threshold, what should happen with the incentive?

A: Entergy should be eligible for incentives in proportion to the estimated performance minus the threshold. In other words, if the incentive rate is 10%, the estimated benefits are $10 million and the threshold is $8 million, the incentive should be ($10–$8) × 0.1 = $0.2 million.

Q: How should incentives relate to program spending?

A: Most incentive schemes provide for maximum incentives that are less than 10% of program costs, such as the following examples:

- Arkansas: 7% for savings above goals
- Arizona: 10%
- Colorado: 20% for lost-revenue compensation plus incentive[28]
- Connecticut: 8% (at 130% of goal)

---

[28]Lost-revenue recovery would probably consume most of this cap, leaving little room for incentives.

- Massachusetts: 5%
- New Hampshire: 8%–12%
- Vermont: 2.6%

Considering that Connecticut, Vermont, and Massachusetts are some of the leading jurisdictions in energy efficiency, there does not appear to be any need for incentives to exceed 10% of program spending; much less is probably adequate.

Q: Should the incentive mechanism be driven entirely by net benefits?

A: Not beyond a transition period. Net total-resource-cost (TRC) benefits are an important measure of the success of a DSM program. Unfortunately, exclusive focus on maximizing TRC benefits, especially in the short term, can result in the utility concentrating almost excessively on a small subset of programs and measures that are easy to implement and produce high TRC benefits, primarily lighting retrofits for large commercial customers and sometimes residential screw-in compact fluorescents.[29] To prevent excessive concentration of effort in these narrow market segments, various jurisdictions have moved beyond shared savings to base incentive mechanisms at least partly on such factors as the following:

- achievement of minimum savings levels in various customer classes, such as residential and non-residential;
- comprehensiveness of savings;

[29]These measures are valuable, but relatively short-lived; the programs are also time-limited, as Federal efficiency standards phase out standard incandescent lamps and the linear fluorescents now standard in commercial installations.

- savings achieved in hard-to-reach market segments, such as low-income residential and small general-service customers;[30]
- energy- and peak-reduction goals;
- geographical equity in program implementation;
- weighted average measure life;
- achievements in new construction, training, and other market-transformation activities.

These factors can be accommodated as separate incentives, or as thresholds or modifiers to a shared-savings mechanism. Development of complex incentive mechanisms is best accomplished through a collaborative process among the concerned parties, rather than in litigation.

VI. Generation Planning Issues

Q: What generation planning issues have you identified in your review of the ENO and ELL IRPs?

A: I have identified the following issues:

- Entergy's inadequate justification of the proposed addition of combined-cycle capacity in 2015 and various limited-term generic planned purchases.
- Entergy's assumption that required reserve margins will rise due to the withdrawal of two Entergy companies from the current system agreement.
- Entergy's limited discussion of the risk of coal-plant shut-downs, and contingency planning for such events.

---

[30]It may also be appropriate to include an incentive for efficiency improvements for industrial customers, who often require more complicated customized solutions compared to comparable-sized commercial customers.

- Limited discussion of the options for promoting supply diversity and local generation through renewables, combined heat and power, and district cooling.

A. Planned Combined-Cycle Addition in 2015

Q: What is Entergy's basis for planning to add combined-cycle capacity in 2015?

A: The SRP Refresh includes 120 MW of new combined-cycle capacity for ENO and 480 MW for ELL; the IRPs include 100 MW for ENO and 400 MW for ELL. (SRP Refresh Tables A-17 and A-18; ENO IRP Table ENOI-10; ELL IRP Table ELL-10) None of these documents provide a specific justification for the amount or timing of these additions.

Q: Does either utility require additional capacity in 2015?

A: No. The SRP Refresh (pp. 31–32) projects that ENO would have sufficient capacity through 2021 without any further additions (even short-term purchases or renewables), and ELL through 2022. These computations are based on each utility maintaining a 10% reserve margin above its non-coincident peak. Due to the diversity of the various utility peaks, the Entergy system coincident peak is less than the sum of the utility non-coincident peaks, so the 10% utility reserves produce an Entergy reserve of about 14%–16%, lower than the 16.85%–20% reserve margins Entergy claims are needed for the system (SRP, Figure 7-1). Even if the reserve on utility non-coincident peak were increase a couple points, ENO still would need no capacity until the retirement of Michoud 2 in 2022, and ELL would have no capacity need until the retirement of Little Gypsy 1 in 2019, or with less than 100 MW of planned renewables or short-term purchase, 2023.

Q: Why does Entergy assume that the required reserve margins for ENO and ELL will increase over time?

A: Entergy projects that the total six-utility Entergy system would require reserves of 16.85%, but that the reserve requirements would increase in 2014 when Entergy Arkansas withdraws from the existing System Agreement and in 2016 when Entergy Mississippi withdraws. Entergy estimates that ENO and ELL would need reserves of 18% in 2014–15 and 20% after 2015, due to these changes in contractual relationships among the Entergy utilities (ENO IRP, pp. 4–5).

Q: Are these expectations warranted?

A: No. The amount of capacity required to maintain reliability does not depend on the financial relationship among the utilities. So long as the Entergy utilities continue to dispatch their plants to maintain regional reliability, the details of their payments to one another for energy, capacity and other services should have no effect on reliability or capacity requirements.

Q: Does Entergy provide any indication as to why it is planning to add the combined-cycle capacity in 2015?

A: The ENO IRP says that "Modern gas-fired CCGT resources are the technology of choice to meet incremental load following needs" (p. ENOI-11) and "ENOI's portfolio lacks modern gas-fired CCGT capacity. System resources must support ENOI's core load following requirements" (p. ENOI-12). Entergy concedes that ENO has more than enough load-following capacity overall, from Michoud, but assigns Michoud to the category of Seasonal Load-Following, rather than the Core Load-Following role of combined-cycle plants (p. ENOI-11)

Entergy seems to have decided that ENO and ELL need more combined-cycle capacity based on the claim that they need more capacity in the Core Load-Following category.

Q: Are Entergy's categories of generation resources standard for the utility industry?

A: No. Entergy uses four categories of generation resources: Baseload, Core Load-Following, Seasonal Load-Following, Peaking and Reserve. (ENO IRP p. 10) Entergy states that "as a guideline," it determines baseload requirements as "the level of firm load that is expected to be exceeded during 85% of the hours in a year," core load-following requirements as the load exceeded in 30% of hours (minus baseload), seasonal load-following as the load exceeded 15% of hours (minus the first two categories), peaking as the peak load minus the first three categories, and reserve as the peak load times the required reserve margin.

Of these five categories, only baseload and peaking are standard concepts in defining generation types. In general, baseload resources are defined as those that are run whenever they are available, while peaking capacity is expensive to run and is operated only at high load levels or when other resources are unavailable. Resources dispatched between baseload and peaking resources are referred to as intermediate or load-following.

Q: How do utilities determine whether they require additional capacity of various types?

A: The basic criterion for selecting new resources is economic. If a utility requires new generation resources, it would generally compare the capital, operating, fuel, and purchased-power costs of the entire system with the addition of feasible resources, such as combustion-turbine peakers, combined-cycle units, and coal capacity, through purchased-power agreements, purchase of existing assets, or construction of new capacity. If the utility has no need for additional capacity for reliability purposes, it would also compare the results with the costs of the existing system.

As fuel prices and system configuration change, the operating roles of power plants change. For example, if gas prices fell further and coal costs rose, Entergy's combined-cycle plants could be dispatched as baseload, pushing the coal plants into a more intermediate role. Similarly, if Entergy's coal plants are retired, some of the gas combined-cycle plants would operate as baseload units.

Q: Does a utility's failure to have the amount of generation specified by Entergy for each category imply that addition of generation in that category is necessary or cost-effective?

A: No.

Q: Has Entergy demonstrated that ENO and ELL need the 2015 combined-cycle plant for reliability or that adding that plant would reduce costs to customers?

A: No. The IRPs, the SRP, and the SRP Refresh all assume the 2015 additions, without any explanation, other than the vague claim that these utilities have less combined-cycle capacity than Entergy's arbitrary targets.

Q: Are there ever other justifications for adding generation resources, other than total capacity requirements and economics?

A: Yes. Some resource additions that would not otherwise be needed may be justified by diversification of energy supply costs and risks, or creating opportunities for development of new technologies. Both those factors may warrant some investment in renewable generation that is not fully justified by the expected economics.

In some situations, utilities needed generation in specific locations with specific operating characteristics. For example, fast-start gas turbines are sometimes required to provide backup for transmission lines in constrained areas.

1 **Q: Do any of these factors justify the addition of combined-cycle capacity for**
2 **ENO and ELL in 2015?**
3 A: No. For Entergy, building gas-fired combined-cycle capacity will neither
4 diversify its already heavily gas-fired supply mix nor resolve important issues
5 regarding the integration of combined-cycle capacity into the transmission
6 system. Entergy has not argued that the system needs the 2015 combined-cycle
7 capacity for any locational or operational purposes, and certainly has not
8 demonstrated any rationale for ENO or ELL providing that capacity.

9 **Q: Should the Council approve the addition of combined-cycle capacity in**
10 **2015 as part of this IRP?**
11 A: No. The Council should inform ENO and ELL that the costs of the combined-
12 cycle will be recovered in rates only if Entergy can justify the plant, based on
13 the economics of adding that resource. If Entergy can find a non-utility
14 combined-cycle plant for sale at a steep discount from new construction, ENO
15 and ELL may save money by purchasing capacity they do not need for reliability
16 purposes.[31] Fuel savings are unlikely to cover the fixed costs of a newly
17 constructed combined-cycle plant, such as the plant Entergy has suggested it
18 might build at Ninemile for 2015 (IR CNO 1-19).

19 ***B. Potential Retirement of Coal Plants***

20 **Q: What is your concern about the treatment of the coal units in the IRPs?**
21 A: The SRP Refresh notes that the Clean Air Visibility Rule is expected to require
22 scrubbers and other environmental controls at Entergy Arkansas's White Bluff

---

[31] According to NERC, the Entergy region has excess capacity to at least 2020, counting only existing resources that NERC considers "certain" to continue in operation. (2010 Long-Term Reliability Assessment, North American Electric Reliability Corporation, October 2010, Table 5e)

plant. It also notes that the concerns of the U.S. EPA about the proposed plan for meeting the Rule's requirements have led to the suspension of the retrofit project and Entergy's request for approval from the Arkansas PSC. It further notes that the delay "generates uncertainty regarding the long-term viability of the White Bluff facility" (SRP Refresh, p. 5). The SRP Refresh also observes that new U.S. EPA rules have been proposed or are expected for SO_2, NO_X, mercury, water intake and waste management, and CO_2. Yet the IRPs do not address the effects of early retirement of White Bluff or Entergy Arkansas's Independence plant.

Since both ENO and ELL purchase White Bluff and Independence power as part of the Wholesale Base Load package, loss of these plants would change the utilities' supply mix. The IRPs should at least consider the magnitude of those effects and cost-effective responses if those contingencies appear more likely in the future.

C. Supply Diversity and Local Generation

Q: What supply resources should be included in the IRP and potentially promoted by Entergy to increase supply diversity and local generation?

A: The IRP should explore in more detail the following subjects:

- whether the ENO should join ELL and Entergy Gulf States Louisiana in procuring wholesale renewable energy supplies,
- the benefits and costs of a feed-in tariff (FIT) for small solar installations in Orleans parish,
- the identification and development of cost-effective opportunities for combined-heat-and-power (CHP) projects in Orleans parish.
- development of district-cooling systems within the parish.

Q: What are the potential benefit of procuring renewable energy from facilities outside New Orleans?

A: The primary purpose would be to diversify ENO's energy supply, which is now a mix of nuclear, coal, and gas. Coal power remains under environmental pressure; while gas prices are low now, they could spike again in the future; nuclear plant output can be curtailed for long periods if generic problems arise with similar plant designs anywhere in the country. Entergy has incorporated biomass projects in the generation plans for both ENO and ELL starting in 2018, with in-stream hydro and off-system wind entering the mix after 2020 (ENO IRP, Figure ENOI-10; ELL IRP, Figure ELL-8).

The Louisiana PSC has implemented a renewable-energy pilot program for its jurisdictional utilities including ELL and Entergy Gulf States Louisiana (LPSC Docket No. R-28271 Subdocket B). The goals of the pilot program include diversifying Louisiana's fuel mix, providing greater energy security through the use of indigenous resources, and allowing Louisiana's utilities to evaluate the characteristics and market for renewable projects. It makes sense for ENO to join in this process.

In addition to the biomass projects that Entergy suggests will initially dominate its renewable supplies, Entergy may find that wind power can be economically developed along the Louisiana coast, or off-shore. Major wind developers have started exploring wind speed at the height of tall towers along the Gulf coast.

Q: What role could a feed-in tariff have in the development of solar energy in New Orleans?

A: The FIT could complement the net metering rate, especially for larger customers. The net metering rate is limited to 100 kW for non-residential customers, but

many commercial, institutional and industrial customers have sufficient roof space for much larger installations. The net metering rate also credits non-residential customers only for energy rates, and not their demand rates (unless the solar cells are producing well in every one of the customer's high-load hour in the month). For a large customer on the Large Electric rate, net metering would save only about 2.6¢/kWh plus the fuel-adjustment charge, currently about 3¢/kWh, for a benefit of less than 6¢/kWh. In contrast, a small residential net metering customer would save about 9¢/kWh.

A feed-in tariff would provide stable and predictable rates for larger solar installations, reducing power flows into New Orleans and reducing stress on the transmission and distribution systems.

Q: What opportunities might exist for development of combined heat and power production facilities in New Orleans?

A: Given the local climate, large heat loads in New Orleans are limited to particular industries, some water-heating loads (such as in central laundries) and absorption chilling, which uses a heat source to drive a cooling cycle. I understand that Folger's Coffee has two roasting plants in New Orleans, which require a large heat input. The hot gases necessary to roast the coffee might be produced by a gas turbine that also generates electricity, or the hot exhaust from the roasting process may be used to operate a steam cycle, or both. The additional reliability of on-site generation may also be advantageous for Folgers, since even brief interruptions of the coffee-roasting process can result in the loss of a substantial amount of product in process.

As the gas utility, ENO should have good information about the extent of heat use by various large commercial and industrial customers, as well as an interest in increasing retail gas consumption. The IRP should include an

assessment of the opportunities for development of combined heat and power facilities. If Entergy identifies attractive opportunities for near-term CHP development, it should come to the Council for approval of its investment and contractual arrangements.

Q: What is a district cooling system?

A: A district cooling system consists of a central cooling facility and a distribution system that carries chilled water to a number of buildings. Such systems are common on university campuses, medical centers, and other multi-building facilities with a single owner. This approach is particularly attractive if the central cooling equipment can be more efficient than distributed equipment, such as by using river water as the heat sink or using off-peak ice storage (reducing the electric load at peak times), absorption chilling run directly off of gas (greatly reducing total electric usage), or absorption chilling powered by waste heat from a CHP plant (producing net electicity).

I understand the Federal City is interested in expanding its district cooling system. Entergy should be working with Federal City and other redevelopment projects to include district cooling wherever it would be advantageous.

Q: Are there any particular benefits to New Orleans of local distributed generation?

A: Yes. Depending on the equipment configuration, distributed generation may allow sections of the city to have power supply after the failure of transmission into the city, or to regain electric service more quickly after a regional power outage. Local CHP may also be useful to Entergy in restarting Michoud and restoring power delivery more widely after an outage.

Q: Does this conclude your testimony?

A: Yes.

AFFIDAVIT

STATE OF MASSACHUSETTES
COUNTY OF MIDDLESEX

NOW BEFORE ME, the undersigned authority, personally came and appeared:

PAUL L. CHERNICK

who, after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof; that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

PAUL L. CHERNICK

SWORN TO AND SUBSCRIBED BEFORE ME,

THIS 20th DAY OF DECEMBER, 2010.

NOTARY PUBLIC

My Commission expires: _____

DIANNE J. DeMARCO
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
September 27, 2013