August 8, 2016

By Hand Delivery and Email

Ms. Lora W. Johnson, CMC
Clerk of Council
Room 1E09, City Hall
1300 Perdido Street
New Orleans, LA 70112

In Re: Resolution Regarding Proposed Rulemaking to Establish Integrated Resource Planning Components and Reporting Requirements for Entergy New Orleans, Inc. (Docket No. UD-08-02)

Dear Ms. Johnson:

Enclosed please find an original and three copies of the Alliance for Affordable Energy's response to Entergy New Orleans' Integrated Resource filing, submitted February 1, 2016. Please file the attached communication and this letter in the record of the proceeding and return one timestamped copy to our courier, in accordance with normal procedures.

Thank you for your time and attention.

Sincerely,

Casey DeMoss
CEO
Alliance for Affordable Energy

cc: Official Service List UD-08-02 (via e-mail)

ENTERGY NEW ORLEANS, INC
In Re: Resolution Regarding Proposed Rulemaking to Establish Integrated Resource Planning Components and Reporting Requirements for Entergy New Orleans, Inc.

Certificate of Service Docket No. UD-08-02

I hereby certify that I have this 8th day of August, 2016, served the required number of copies of the foregoing correspondence upon all other known parties of this proceeding, by electronic mail.

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Casey DeMoss
CEO
Alliance for Affordable Energy

ENTERGY NEW ORLEANS, INC
IN RE: PROPOSED RULEMAKING TO ESTABLISH INTEGRATED RESOURCES PLANNING COMPONENTS AND REPORTING REQUIREMENTS FOR ENTERGY NEW ORLEANS, INC.
UTILITY DOCKET NO. UD-08-02
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An Integrated Resilience Plan for New Orleans City Council

August 8, 2016

Prepared by the Alliance for Affordable Energy

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Lazard
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National Energy Technology Laboratory (NETL)
Mid-Continent Independent System Operator (MISO)

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CHAPTER 1

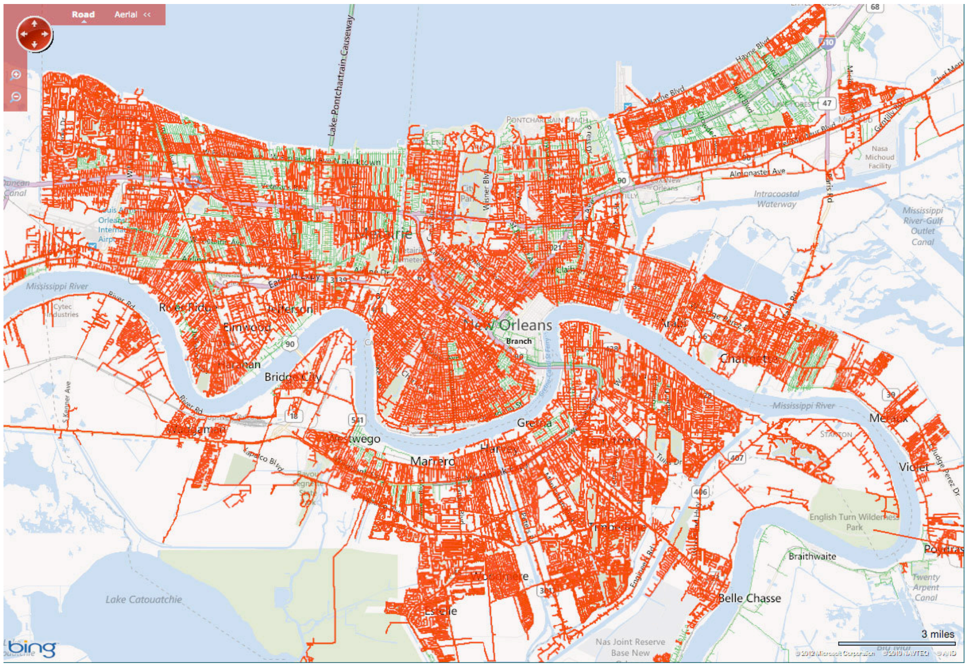
THE CASE FOR INTEGRATED RESILIENCE PLANNING

Overview

It is no secret that New Orleans is vulnerable to storms and that the City needs to become more resilient to their impacts. The City's energy system is no exception; hurricanes and storms in the last 15 years have shown the system to be vulnerable to water and wind damage. To address these vulnerabilities, the New Orleans' City Council tasked ENO to develop a storm hardening plan.[1] Unfortunately, after many months ENO submitted a plan that was wholly inadequate as described in the Council's Show Cause resolution.[2] The resolution stated "[a]dvisors' concerns was that the report only addressed normal conditions and did not speak to ENO's resilience in storm and/or hurricane conditions."

Similarly, in ENO's IRP filing, the company cites reliability as the chief reason to build a new, albeit smaller, natural gas plant at the same site as the previous Michoud Generating Unit. However, the Alliance questions whether the city will have sufficient reliability from a single source, located at the farthest end of the city's infrastructure in a vulnerable location. The Michoud units illustrated why a single site solution is insufficient to remediate water and wind vulnerabilities. Although the Michoud units were available until June 2016, having this capacity did not protect most New Orleans customers from outages during storms in the last decade. The map below of Hurricane Isaac outages perfectly illustrates that storm hardening efforts are vital to preserving and strengthening the city's resilience.

Figure 1.1 Isaac Outage Map[3]



Source: Screenshot from Entergy's Power Outage Map, August, 2012.

The table below shows some of the expected infrastructure impacts of hurricanes, and highlights a need for resilience planning that meets the needs of New Orleans customers in various scenarios. Importantly, probability of loss of electrical power is rated medium and severity of damage significant even for tropical storms.

Figure 1.2 probability/severity of Hurricane Damage

Infrastructure	Tropical Storm (39-73 MPH)		Hurricane Cat 1-2 (74-95 MPH, 96-110 MPH)		Hurricane ≥ Cat 3-5 (111-129 MPH, 130-156 MPH, >157 MPH)	
	Probability of Damage	Severity of Damage	Probability of Damage	Severity of Damage	Probability of Damage	Severity of Damage
Loss of Electrical Power	Med	Significant	Med-High	Major	High	Catastrophic
Gulf of Mexico Platforms	Low	Insignificant	Med-High	Major	Med-High	Major
Pumping/Compressor Station	Low	Insignificant	Med	Significant	Med-High	Major
Pipelines	Low	Insignificant	Low-Med	Interrupting	Med-High	Major
Rail	Low	Insignificant	Low-Med	Interrupting	Med-High	Major
Ports	Low	Insignificant	Med-High	Major	High	Catastrophic
Crude Tank Farm	Low	Insignificant	Low-Med	Interrupting	Med	Significant
Refineries	Low	Insignificant	Med	Significant	Med-High	Major
Natural Gas Plants	Low	Insignificant	Med	Significant	Med-High	Major
Product Storage Terminals	Low	Insignificant	Low-Med	Interrupting	Med-High	Major
Propane Tanks	Low	Insignificant	Low	Insignificant	Low	Insignificant
Underground Storage	Low	Insignificant	Low	Insignificant	Low	Insignificant
LNG Terminals	Low	Insignificant	Med	Significant	Med-High	Major
Local Gas Distribution	Low	Insignificant	Med	Significant	Med-High	Major
Filling Stations	Low	Insignificant	Med	Significant	Med-High	Major
SPR/NEHHOR	Low	Insignificant	Low-Med	Interrupting	Med	Significant

Source: U.S. Department of Energy, 2015.

City Council Leadership and Vision

The City Council has shown great wisdom in retaining energy regulatory authority over the investor-owned utility company, Entergy New Orleans. New Orleans has been recognized for their leadership and foresight by numerous organizations, government agencies, and the press. Thanks to the regulatory leadership of the City Council, New Orleans has proven to be an exporter of smart energy policy. For example, energy efficiency rules passed by the City Council were among the first in the deep south and following New Orleans' example, the state Public Service Commission passed energy efficiency rules 5 years later. Integrated Resource Planning and solar net-metering policy were also adopted by the state regulatory body after proving successful in New Orleans.

A defining feature of the Council's regulatory oversight is the Integrated Resource Planning

(IRP) process that purports to assure Entergy invests in the mix of resources over the planning horizon that will provide the greatest value to New Orleans residents and businesses, all things considered. The IRP process sets forth a method to evaluate the many options to meet the needs of the utility system and to consider the many values at stake in those choices. An open, multi-stakeholder process is vital to a good outcome in the IRP.

The IRP process lays the foundation for decisions such as how much power is needed, including reserve requirements, whether local installed generation capacity is needed, how much to invest in energy efficiency programs, demand response programs, and renewable energy resources, among other things. The IRP does not definitively answer those questions. It informs them with vital facts.

A False Choice

Entergy has presented the Council with only two choices, brownouts or a new CT gas plant. This is a false choice. The Alliance is presenting fact-based alternatives for the Council to consider further. In the 2015 IRP proceeding, Entergy New Orleans restricted the modeling outcome to ensure a specific outcome: a new combustion turbine gas power plant. This was accomplished in several ways including but not limited to:

1. Ignoring Council directive to establish annual targets for energy efficiency (Resolution No. R-15-599;
2. Inflating renewable energy costs by using old cost data (solar cost data from 2013);
3. Lacking transparency by citing reports that were "proprietary" (IHS CERA), not citing any source for costs (wind);
4. Ignoring viable resource options that warrant consideration by the Council;
5. Failing to acknowledge major utility industry trends that reveal economically attractive clean energy options that comply with Council's stated policy goals; and
6. Failing to produce an IRP with multiple plans as is industry standard practice.

To be clear, the Alliance supports local generating capacity in Orleans Parish. The very real danger of storm damage to our system requires smart resiliency planning. We simply do not believe there is sufficient evidence to support the idea that a single, centralized, natural gas plant, in a location with known vulnerabilities, is the most resilient choice. The Integrated Resilience Plan (IResP) simply seeks to offer more choices that maximize benefits and minimize external costs.

City of New Orleans Resiliency Planning

The City and its New Orleans Redevelopment Authority has been doing excellent work on making our city safer against future disasters. The New Orleans Master Plan devotes an entire chapter to city resilience in the face of more powerful storms and sea level rise.[4] Resilient NOLA [2015] offers a broad scope to fulfill New Orleans' security needs and the energy sector should be no exception to critical resilience planning. In 2014, the City joined the Rockefeller Brothers Foundation to become one of the 100 Resilient Cities of the world. In August 2015, the City published the City Resilience Plan that outlined three visions for the city that touch on energy systems and resource planning:

1. Adapt to Thrive: We are a City That Embraces Our Changing Environment
    a. Invest in comprehensive and innovative urban water management (groundwater use)
    b. Commit to mitigating our climate impact (carbon emissions from power generation)
2. Connect to Opportunity: We are an Equitable City
    a. Continue to promote equitable public health outcomes (public health risks associated with power generation)
    b. Continue to build social cohesion (environmental justice and pollution)
3. Transform City Systems: We are a Dynamic and Prepared City
    a. Improve the redundancy and reliability of our energy infrastructure (retaining power during and after storms)
    b. Integrate resilience-driven decision making across public agencies (coordinating efforts between City Council, Entergy, Sewage & Water Board, NORA, and local nonprofits and businesses).

One of the ways the City has already begun to fulfill these visions is the pursuit of micro-grid technologies. The City was successful in securing grants from the Department of Energy to study resilience and redundancy in our power grid. Through this grant, NORA, Entergy, and local nonprofits and businesses are coordinating with Sandia Labs on a micro-grid study. The first micro-grid is set for development in Gentilly. This is an exciting opportunity to the city.

Legal Framework for a Supplemental Resource Plan

The Alliance has prepared an alternative plan for the Council's consideration. AAE wishes to maintain the integrity of the IRP process by fulfilling the prescribed legal standards for integrated resource planning where it feels Entergy New Orleans has failed to do so. Additionally, the Alliance believes that the ratepayers of Orleans Parish will benefit only when the Council has been given the opportunity to review every potential method of meeting the area's future needs.

As in many jurisdictions, the City Council has designed a specific process for how integrated resource plans should be prepared, organized, and delivered to the Council and the public.[5] One of the requirements ENO is supposed to fulfill in its IRP filing is: "[t]he IRP must provide an evaluation of various resource mixes showing both the expected outcome in terms of average price and the potential range of outcomes around the expected price".[6] All of the "alternative portfolios" ENO provided within its final IRP contain a combustion turbine.[7] This is an insufficient selection of various resource mixes as the majority of the energy in each portfolio comes from the same source. It is standard practice in many jurisdictions to require utilities to evaluate multiple portfolios that contain an actual variety of resources.[8] ENO should not be able to skirt its responsibilities to the Council and rate-payers by offering portfolios that are alternatives in name only.

It is the belief of the Alliance that the great importance of the provisions in Resolution R-10-142 lies in the Council's ability to knowledgeably evaluate ENO's preferred energy portfolio. It is difficult to imagine how the Council could compare alternative options when only superficial "alternatives" have been provided.[9] Although the Alliance has been an active and vocal participant throughout the IRP process, its contributions have been largely ignored by ENO.[10] Therefore, the Alliance has created what it believes to be required alternative portfolios.

Economic Development

New Orleans City Council members are rightly focused on local economic development. The Alliance agrees that ratepayer dollars should be utilized primarily in New Orleans ensuring that those bearing the financial costs of energy are also the benefactors of utility investment. According to the EPA, there are multiple economic benefits associated with energy generation.[11] However, utility investments in all resources, including energy efficiency have proven to be sources of local economic development.

Jobs, Income, Economic Output

- $1 million of energy efficiency net benefits in Georgia produces 1.6–2.8 jobs[12] (Jensen and Lounsbury, 2005).
- $1 million invested in energy efficiency in Iowa produces 25 job-years
- $1 million invested in wind produces 2.5 job years[13] (Weisbrod et al., 1995).
- Every $1 spent on concentrated solar power in California produces $1.40 of additional GSP[14] (Stoddard et al., 2006).
- Every $1 million invested in wind or PV produces 5.7 job-years, versus 3.9 job-years for coal power[15] (Singh and Fehrs, 2001).
- Every $1 spent on energy efficiency in Iowa produces $1.50 of additional disposable income[16] (Weisbrod et al., 1995).
- Every $1 million in energy savings in Oregon produces $1.5 million of additional output and about $400,000 in additional wages per year[17] (Grover, 2005).

Every opportunity to reinvest money on local infrastructure and job creation should be pursued. The IResP seeks to maximize these opportunities and economic development will be a factor in determining the final recommendations.

Calculating the Full Cost of Power Generation: Externalized Costs

The City Council and the Alliance have both stated concern for the pollution that fossil fueled energy generation creates. In an effort to capture the costs of that pollution, the Alliance successfully partnered with the Louisiana Public Health Institute to conduct a Health Impact Assessment. For many years, the Alliance has encouraged Entergy to consider quantifying the costs of the pollution they generate by including a carbon price per ton of emissions. Entergy failed to include a price on carbon in the preferred model utilized in their 2015 IRP. The Alliance asserts that excluding a known cost as set forth by the EPA is fiscally irresponsible to their customers and shareholders.

For the purposes of creating a resilient energy resource plan, we considered the health costs of toxic pollution to children, senior citizens, and surrounding neighborhoods. According to the EPA, a study on health impacts showed that for every ton of carbon reduced, the public received $3-90 in health and visibility benefits.[18] Connecticut found that their energy efficiency program earned $3 for every $1 direct return plus an additional $4 in reduced health costs.[19]

Conclusion

Proper storm hardening, distributed generation with Combined Heat and Power installations, fired efficiently by natural gas, battery backup combined with new and existing solar are just a few of the many choices that the Alliance is presenting to the Council for further thought and analysis. We can work together to build a more resilient city. We can have a safe, reliable energy grid for the whole city. We can achieve these goals affordably.

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[1] New Orleans City Council, Storm Hardening Resolution R-15-31 January 22, 2015 Docket UD-12-04
[2] New Orleans City Council, Show Cause Resolution R- June, 2016 Docket UD-16-01
[3] Nola.com, Power outage map shows Issac's effect on area grid. Swensen, D, August 29, 2012. Available at http://www.nola.com/hurricane/index.ssf/2012/08/power_outage_map_shows_isaacs.html
[4] New Orleans City Master Plan, Volume 2, Chapter 12, Resilience. 2010. Available at http://www.nola.gov/city-planning/master-plan/
[5] These provisions can be found in the attachment to Utility Committee Resolution R-10-142 titled "Electric Utility IRP Requirements of the Council of the City of New Orleans 2010". The standards set forth in this attachment were made applicable to future IRP processes in Resolution R-11-310. The "Electric Utility IRP Requirements of the Council of the City of New Orleans 2010" elaborates on the components the Utility Committee found necessary for a functioning IRP process.

[6] R-10-142 In Re: Resolution Regarding Proposed Rulemaking to Establish Integrated Resource Planning Components and Reporting Requirements for Entergy New Orleans, Inc. attachment "Electric Utility IRP Requirements of the Council of the City of New Orleans 2010". March 25, 2010. See paragraph 15 of Component 3.
[7] See ENO 2015 Final Report. pg. 55 – 61.
[8] See Arizona Administrative Code R14-2-703(D) which reads: "A load-serving entity shall, by April 1 of each even year, file with Docket Control the following prospective analyses and plans***, which shall compare a wide range of resource options***..." AZ ADC R14-2-703 "Load Serving Entity Reporting Requirements", Feb. 3 1989. Emphasis added.

See Also Georgia Administrative Code 515-3-4-.05(b)(4) which reads: "The utility shall provide the following information for its integrated resource plan: (4) ***Practical alternatives to the fuel type and method of generation*** of the proposed electric generating facilities and set forth in detail the reasons for selecting the fuel type and method of generation." GA ADC 515-3-4-.05 "Development of an Integrated Resource Plan", Dec. 30, 1991. Emphasis added.

See Also Missouri Code of State **Regulations** 4 MO ADC 240-22.060 which reads: **"…*The goal is to develop a set of alternative plans based on substantively different mixes of supply-side resources and demand-side resources*** and variations in the timing of resource acquisition to assess their relative performance under expected future conditions as well as their robustness under a broad range of future conditions." 4 MO ADC 240-22.060 "Integrated Resource Plan and Risk Analyses", June 12, 1992. Emphasis added.
[9] Ibid. FN 3.
[10] New Orleans City Council, Show Cause Resolution R- June, 2016 Docket UD-16-01
[11] Environmental Protection Agency (2011) Assessing the Multiple Benefits of Clean Energy, A Resource for States.
[12] Jensen, V., and E. Lounsbury. 2005a. Assessment of Energy E ciency Potentia in Georgia. Prepared for the Georgia Environmental Facilities Authority by ICF Consulting. May.
[13] Weisbrod, G., K. Polenske, T. Lynch, and X. Lin. 1995. The Long-Term Economic Impact of Energy E ciency Programs and Renewable Power for Iowa: Final Report. Economic Development Research Group, Boston, MA. December.
[14] Stoddard, L., J. Abiecunas, and R. O'Connell. 2006. Economic, Energy, and Environmental Bene ts of

Concentrating Solar Power in California. Prepared by Black & Veatch for U.S. DOE National Renewable Energy Laboratory. April.

[15] Singh, V. and J. Fehrs. 2001. The Work That Goes Into Renewable Energy. Renewable Energy Policy Project Research Report. November.

[16] Weisbrod, G. and B. Weisbrod. 1997. Measuring Economic Impacts of Projects and Programs. Economic Development Research Group. April.

[17] Grover, S. 2005. Economic Impacts of Oregon Energy Tax Credit Programs (BETC/RETC). Prepared by ECONorthwest for the Oregon Department of Energy. February.

[18] Burtraw et al., (2001) Environmental Protection Agency

[19] Connecticut GSC on Climate Change, 2005

CHAPTER 2

PROJECTED CAPACITY LOAD & TRANSMISSION PLANNING

Overview

Capacity load projections are vitally important in developing a plan for existing and future resources for New Orleans. As with ENO's IRP, this filing uses Peak Load requirements to define "targets" for resource needs coupled with MISO's capacity requirements. ENO has a Planning Reserve Margin of 12% in order to meet the tariff requirements.

However, projected capacity load does not tell the whole story. In addition to meeting capacity load from generating resource, the utility must also meet transmission system requirements. This is because successful delivery of electricity to customers is wholly dependent on a functioning system of transmission lines. This section provides a brief critique of Entergy New Orleans' stated capacity load projections along with an overview of its transmission system, its relation to the Entergy Transmission Organization, and its participation in the Midcontinent Independent System Operator (MISO) transmission organization.

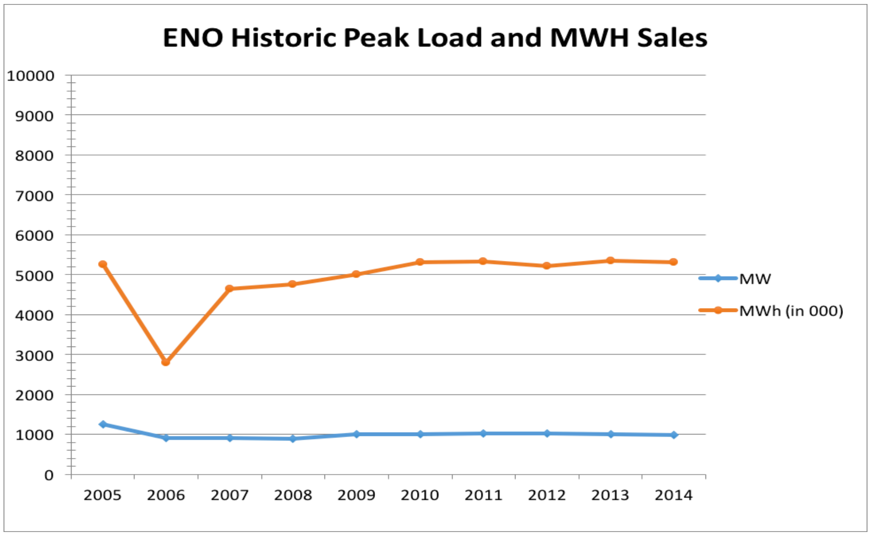
Load Projections Not Supported By Evidence Flat Demand Trend

The Alliance questions ENO's long term load projections, which are insufficiently justified and run contrary to actual New Orleans historic load data trends in recent years (see table **2.1** below). ENO asserted that the peak load requirement in the Stakeholder Input case is 1301 MW by 2035, for a total resource need of 1,451 inclusive of reserve margin requirements. This chapter will discuss the factors of uncertainty in ENO's projected peak load.

Flat Demand Trend

ENO's actual reported peak load has stayed relatively flat after the city's population stabilized following the disruption of Hurricane Katrina.

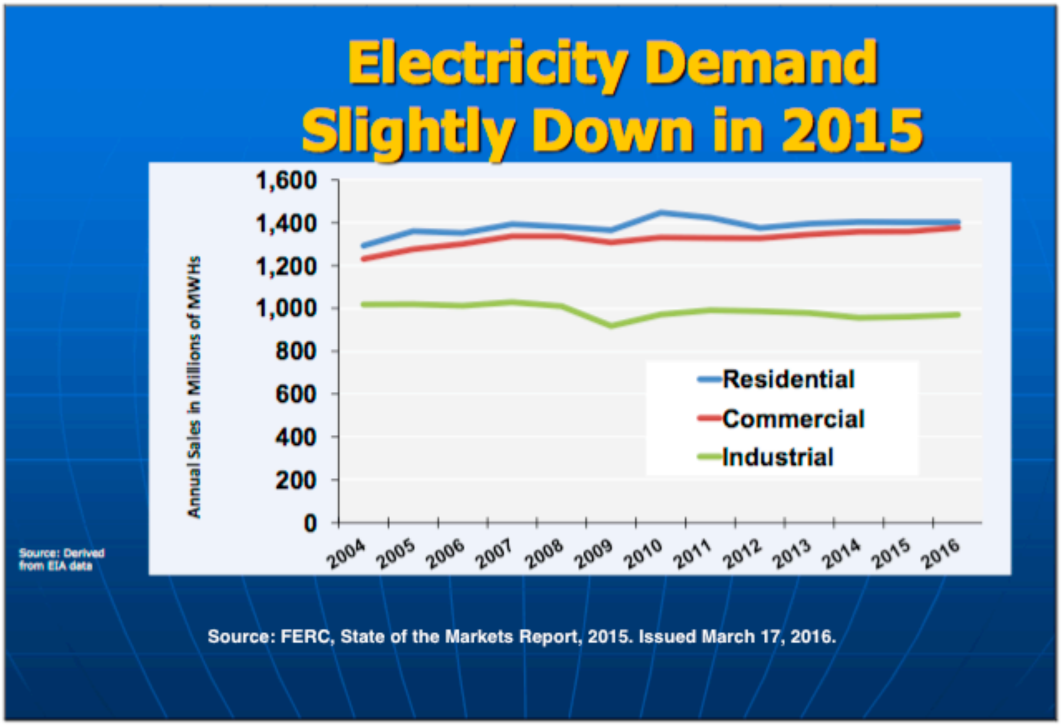
Figure 2.1



This flat demand is in line with MISO's recent Organizations of MISO States (OMS) Survey results[1]. Each fall MISO's Load Serving Entities (LSE) submit self reported load projections to the Independent System Operator, for Resource Adequacy planning. The most recent OMS Survey Results, released in June of 2016 state, "...current forecasts of modest load growth [by LSEs] are not in line with recent history of flat year-to-year loads [in the system]." While individual utility and MISO system projections should not be considered identical, this statement is important for two reasons.

First, MISO is acknowledging their own system-wide and national trends[2] of flat or declining load and sales growth, including national electricity sales down 1.1% from 2014-2015, partly as a result of distributed generation and demand side management programs. Second, fair estimations of load growth are critical for purposes of cost projections in the MISO market, which will be considered in following pages.

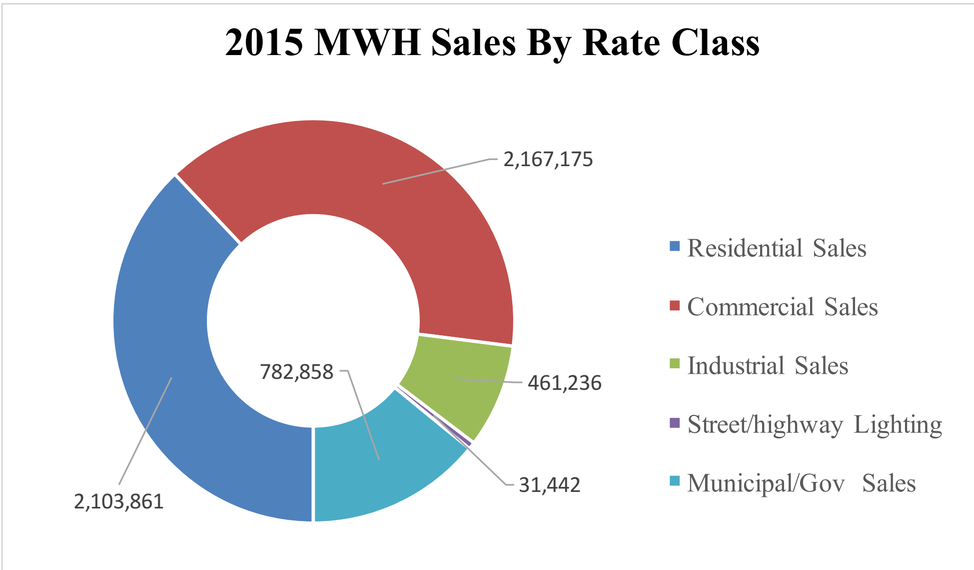
Figure 2.2 FERC State of the Markets Report



When one compares the load projections from ENO's 2012 IRP[3] to the figures presented by ENO in Supplement 6 from June 2015 there is a significant jump, followed by another increase in load requirements in ENO's February 1st, 2016 filing. Using the year 2031 for comparison, the figure increased from 1,099 MW in the 2012 IRP, to 1,291 MW in the June 2015 filing, and then increases again to 1,412 MW in the February 2016 filing. While the difference between the 2015 filing and 2016 filing are a result of the addition of Algiers, the unexplained increase from the 2012 IRP to the 2015 filing shows an increase of 192 MW, representing a 15% unexplained increase from the previous IRP, even while ENO's load was relatively flat, The capacity shortfall that Entergy claims exists and uses to justify the need for building a new CT resource evaporates without these unexplained inflated peak load projections.

In 2015, ENO experienced a peak demand of approximately 1069 MW with 5,546 GWh of retail sales. Approximately 38% of 2015 retail energy was sold to the residential class, 39% to commercial rate classes, and approximately 8% sold to the industrial rate class. Customer classes such as municipal street lighting, etc. accounted for the remaining sales.[4]

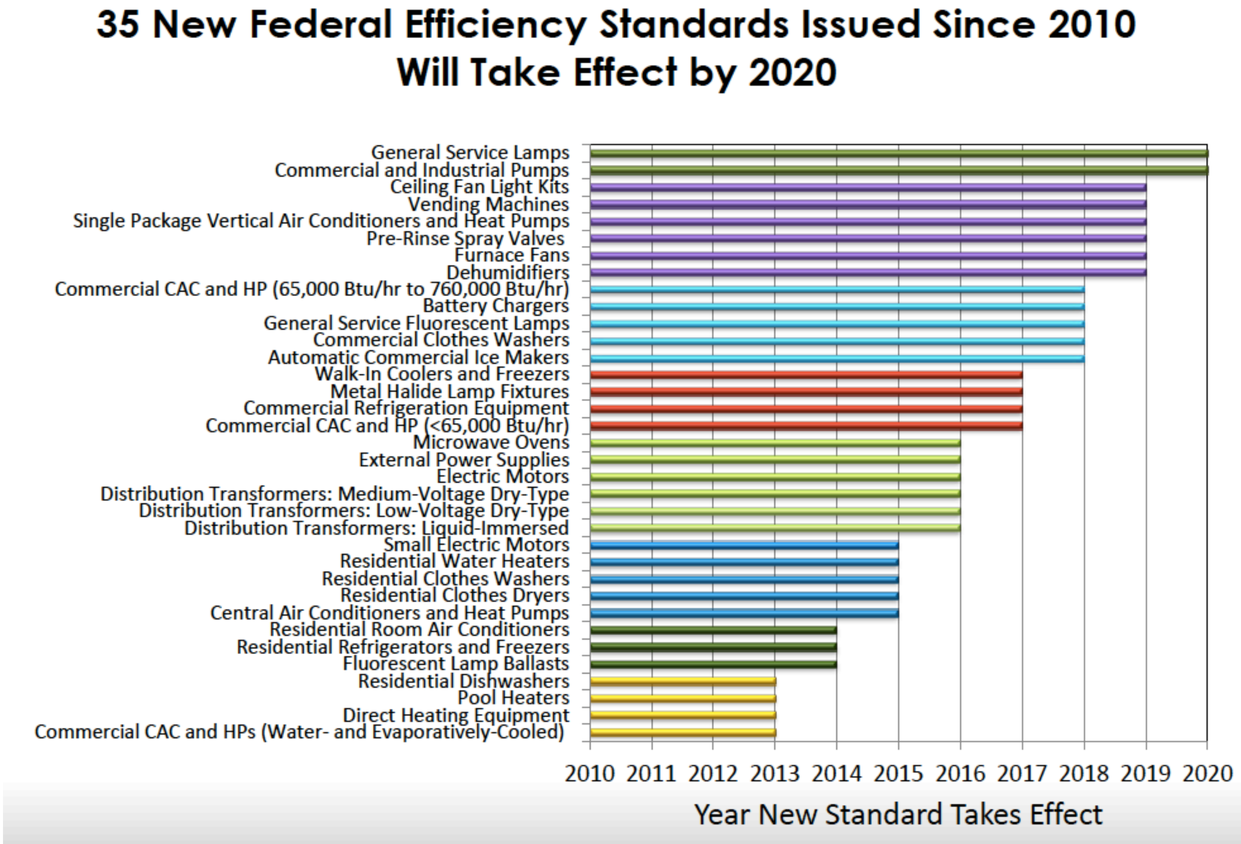
Figure 2.3 2015 MWh Sales by Rate Class



Without providing supporting explanation, Entergy New Orleans projects kWh usage per individual residential customer increasing from 1,081 monthly to 1,332 monthly in ENO legacy territory and to 1,561 in ENO Algiers territory[5]. For ENO legacy this represents a CAGR of energy use of 1.05%. While there is a distinct difference between energy and demand, it is unrealistic to expect that either demand or energy sales will increase in this way with implementation of the Council's resolution for robust demand side management. This level of load growth is particularly improbable with the addition of new Energy Smart Demand Response programs, beginning in 2016, which are designed to specifically target peak load.

Additionally, outside ENO's current DSM programs, load reductions are expected as a result of improvements to national lighting and appliance standards, and with increasingly stringent building energy codes. National appliance standards alone have proven successful, reducing energy use intensity (EUI) for buildings by 6% from 2010 to 2015. The appliance efficiency program's goals for 2025 are EUIs at least 20% lower than 2010.[6] These market transformations, along with initiatives like New Orleans' Downtown Energy Efficiency Challenge and more savvy customers make overall load growth even more unlikely[7].

Figure 2.4



Source: Tom Eckman, Seventh Northwest Power Plan, Key Findings and Implications

Council DSM Targets Exceed Projected Load Growth

DSM is the most effective, as well as cost-effective, strategy for meeting New Orleans' future energy needs. The Council has established DSM targets, which, when modeled, show they will provide significant energy and capacity savings. By placing a priority on peak shaving through targeted EE programs, demand response, and volt var optimization, the savings potential is even greater. This is important because DSM is not merely replacing generic wholesale power from the open market, it will be more than capable of offsetting and completely avoid the need for a new CT power plan. To address projected load growth and resource adequacy requirements, all New Orleans needs is to implement the DSM targets that are already in place.

Distributed Generation

Further reductions to ENO's demand as a result of residential rooftop solar installations will put further downward pressure on ENO's peak load. ENO's IRP projects a CAGR of 0.7% across all scenario assumptions, including "Distributed Disruption," which would by definition reduce demand. This flaw points to further problems in forecasts and assumptions. ENO has made projections within Council Docket No. UD-13-04 on distributed generation, forecasting continued growth of rooftop solar (without additional incentives) at 7% annually.

As costs of battery installations fall and solar customers install storage for resilience reasons, the growing installed solar capacity in the city (already at nearly 36MW) will have a significant impact on peak load. The IRP should be consistent with ENO figures in other dockets and should include clear load effects of solar customers, both historically and projected, as this demand side reduction is considerable. While ENO's February filing suggests distributed generation was included as demand side management, it is not clear how or if ENO calculated growth from this impact.

If ENO's load projections showing growth over the time horizon are incorrect, the need for additional peaking generation is deferred if not nullified. ENO's IRP appears to force a "need" for generation capacity prematurely through unlikely assumptions and projections.

Current and proposed resources must meet the load requirements. ENO must maintain reliable service going forward, thus both need and resources must be fully and accurately justified and verified if it is to be used as the basis for major new resource acquisition. Customer costs are dependent upon accurate forecasting, and while weather and other external factors make exact forecasting difficult, impacts to customers must be considered as a priority in resource planning. Resource forecasting is vital, not only to meet demands, but to anticipate market forces that will directly impact costs to consumers. Excess capacity owned by one utility is not a benefit to utility consumers in a market that also has excess capacity.

MISO's Resource Adequacy Survey Shows Low Cost Capacity Markets

Contrary to ENO's assertion of looming price spikes in the capacity markets, MISO's most recent resource capacity forecast shows that the southern region (zones 8, 9, and 10) will continue to have capacity in excess of the reserve margin until 2022. MISO has also stated that recent projections for load growth by electric utilities are inconsistent with the flat-loads that have actually been observed in recent years. This suggests an even longer time horizon for accessing cost effective surplus capacity in the MISO market. This fact should not be ignored in light of the higher than expected customer bill impact for Union Power Station that resulted from ENO's mistaken projections about capacity prices in the regional marketplace. Because lower demand projections and greater excess capacity in regional markets place downward pressure on MISO capacity prices, New Orleans has the time necessary to carefully consider and pursue its clean energy options, rather than being rushed into a potential boondoggle with ENO's proposed natural gas CT power plant.

Market Access

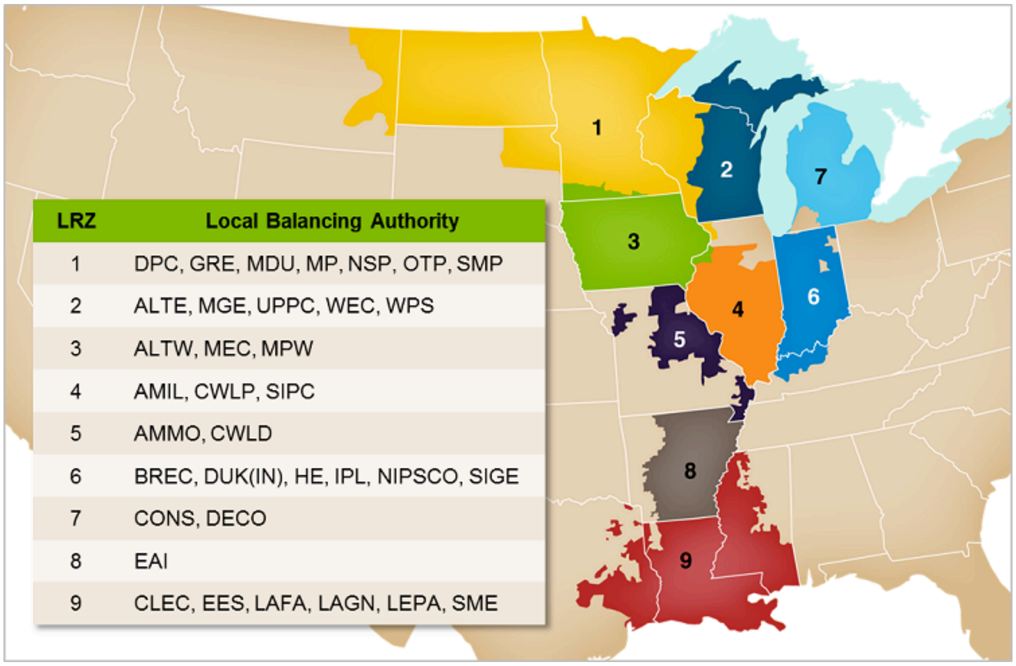
MISO has already indicated that New Orleans has sufficient resource capacity to serve New Orleans' power needs, otherwise they would not have been able to approve the decommissioning of Michoud. To do so, MISO required transmission upgrades in and to the ENO territory, which cost Entergy New Orleans customers $30 million dollars. This transmission investment and others currently being considered, expand ENO's resource options in ways ENO seems to have ignored in their IRP filing. As a result, New Orleans not only has even greater access to power for increased safety and reliability in emergency circumstances, the city can also take advantage of low cost renewable energy resources and PPA contracts. Accordingly, the alternative portfolios offered in this chapter consider both local and transmission accessed power options, without restriction to power purchases from Entergy operated companies.

Transmission Overview

Entergy New Orleans' transmission system serves approximately 197,000 electric customers.[8] ENO currently owns 22 substations and 158 miles of transmission lines. ENO's transmission lines are part of the overall Entergy Transmission System, which is tasked with operating and maintaining the transmission lines throughout the entirety of the Entergy electrical service area. The total Entergy transmission system is made up of 1,500 substations and 15,500 circuit miles of transmission lines operated at 69 to 50 kV.[1] ENO's system is comprised of 11 substations sited throughout the parish connected by 158 miles of transmission lines. Currently there are 8 transmission lines entering the ENO system, six 260KV lines and two 215KV.

ENO, like the other members of the Entergy Transmission System, are transmission owner members of the Midcontinent Independent System Operator (MISO) transmission organization, which controls 66,000 miles of transmission lines in 15 states.[9] Entergy New Orleans joined MISO in December, 2013 along with the rest of the Entergy System and a handful of other utilities in Louisiana, collectively called MISO South.

Figure 2.5 Mid-Continent Independent System Operator (MISO) System & Zones



LRZ	Local Balancing Authority
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA, SME

Local Transmission Planning

The Entergy Transmission System (ETS) is responsible for planning safe and reliable transmission to its utilities and has its own set of criteria for local planning that must be submitted to MISO. This Local Planning Criteria is used to conduct studies of local transmission system load flow, short circuit, and stability.[10] The studies are intended to evaluate both security and adequacy of reliability based on NERC and SERC standards. The criteria identify software programs that should be used in evaluating the existence of reliability contingencies, stability, and short circuits in the transmission system.

Reliability simulations are intended to model a transmission system's ability to handle specific incidents. These simulations include: no contingencies; the loss of a single bulk transmission element; the loss of multiple bulk electric system elements; and extreme event resulting in two or more bulk electric system elements removed or cascading outages. The results of these simulations allow ETS to evaluate potential mitigation plans or plan to improve the transmission system. ETS and ENO do not appear to have more stringent storm hardening criteria than NERC standards.

MISO Transmission Expansion Process

MISO conducts transmission planning annually for the entire MISO system footprint in order to certify safe, reliable access to power, reducing congestion, and improving system benefits. According to the MISO Transmission Expansion Process (MTEP) study published in 2015, there were over $600 million of baseline reliability transmission projects planned in the MISO South region alone.[11] With additional projects, the total anticipated investments in MISO South transmission capabilities total $980 million. In fact, four of MTEP 2015's ten largest projects were planned in the MISO South region, and the first and third largest in order of cost are located in Louisiana.[12] In 2014, ENO had three baseline reliability projects approved by MISO.[13]

Currently, through the MTEP and Economic Planning Users Group (EPUG), a handful of alternatives for transmission projects are being considered to answer transmission congestion issues for the Downstream of Gypsy region (DSG), of which New Orleans is a part.[14] Generally, all of these alternative transmission upgrades offer more resiliencies to New Orleans. According to materials from MISO's EPUG July meeting, it appears that three "best fit solutions" address current and upcoming congestion and reliability issues for DSG and include upgrades that would allow better access to energy imported from outside the DSG load pocket.[15] These three alternatives offer various solutions, price points, and cost allocations that would support and benefit ENO and alleviate New Orleans' transmission islanding problems all with cost to benefit ratios well above 1 and with considerable additional value to customers.

MTEP planning does not require additional transmission hardening for weather events beyond NERC standards. Entergy New Orleans should elect to improve resilience with transmission solutions beyond the MTEP planning process. The Alliance presents suggestions about this in Chapter 6.

Potential Transmission Projects

During MTEP and EPUG planning for 2016, a transmission project alternative (DSG alternative 3) was included to increase transmission and move more power from Union Carbide substation to Paris substation, located in the New Orleans "island." [16] The project would add an additional transmission connection to New Orleans' eight existing transmission lines to generation outside of the city. While this particular project did not make it through the screening process for 2016, it will move to future planning MTEP because it still has substantial benefit to cost ratio. Most importantly, it offers New Orleans a transmission approach to improving access to capacity from outside the "island." This particular transmission project would make a connection between the Occidental-Taft plant even more robust.

Conclusion

Entergy New Orleans has not clearly justified their peak load increases over the time horizon. Recent local and national trends, regulations, market forces, and ENO's own required Demand Side Management programming, all suggest flat and reduced load growth.

Entergy's Transmission System, with planning support and operation by MISO offers continued planning upgrades to improve access to energy from outside Orleans Parish, including planning that increases safety and reliability. Robust transmission planning should be considered a resource, as upgrades to the transmission system serve to expand ENO's resource options and improve the entire Entergy Transmission System.

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[1] 2016 Organization of MISO States Survey Results, June 2016. Available at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Workshops%20and%20Special%20Meetings/2016/OMS-MISO%20Survey/2016OMS-MISOSurveyResults.pdf.

[2] FERC, State of the Market, 2015. Issued March 17, 2016. Available at https://www.ferc.gov/market-oversight/reports-analyses/st-mkt-ovr/2015-som.pdf

[3] 2012 IRP_Data_Supplement_2 Aurora Macro Inputs.pdf page 10

[4] Entergy New Orleans, FERC Form 1, 2015. Filed April 18, 2016.

[5] Entergy New Orleans IRP, February 1, 2016.

[6] Appliance and Equipment Standards Program, Peer Review. Cymbalsky, J. 2016. Available at http://energy.gov/sites/prod/files/2016/04/f30/Cymbalsky%2C%20John_Standards.pdf

[7] Resilient New Orleans: Strategic Actions to Shape Our Future City, Hebert, J. August, 2016. Available at: www.resilientnola.org

[8] Entergy, "About Entergy New Orleans". http://www.entergy-neworleans.com/about_entergy/. (hereinafter About ENO).

[9] Entergy, "Transmission System Facts". http://www.entergy.com/energydelivery/transmission_system_facts.aspx.

[10] Entergy Transmission. Local Planning Guidelines and Criteria. January 27, 2015. Available at: https://www.misoenergy.org/Library/Repository/Study/TO%20Planning%20Criteria/Entergy%20TO%20Planning%20Criteria.pdf.

[11] MISO Transmission Expansion Planning, 2015. https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP15/MTEP15%20Full%20Report.pdf. (Hereinafter, MTEP)

[12] Ibid. pg. 21

[13] MTEP 2014, Appendix D1 South. Available at https://www.misoenergy.org/Library/Pages/ManagedFileSet.aspx?SetId=2273.

[14] Project Candidate Selection- Amite South/DSG &WOTAB.Western, April 15, 2016. Available at:https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2016/20160415/20160415%20EPUG%20Item%2005a%20Project%20Candidate%20Selection.pdf

[15] Reliability No Harm Analysis- EPUG, July 14, 2016. Available at https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2016/20160714/201607%20EPUG%20Item%2003%20Reliability%20No-Harm%20Analysis.pdf.

[16] Project Candidate Selection- Amite South/DSG &WOTAB.Western, April 1

CHAPTER 3

EXISTING RESOURCES AND RESILIENCY

Overview

This section briefly describes the existing capacity mix that ENO either owns or has under contract including resources obtained in the Algiers acquisition. The data presented here are simply facts about ENOS's current sources of electricity generation, the emissions of those units subject to environmental regulation, and their capacity.

Existing Resource Portfolio

Below in Table **3.1** are ENO's generating assets and purchase power agreements (PPAs) with corresponding MW capacity, fuel source, load type. The retirement date of one resource, White Bluff, has also been included. However, ENO did not include any retirement date assumptions in the 2015 IRP and the Alliance was unable to locate the retirement dates of the remaining resources in other available Entergy filings. This is necessary information when analyzing portfolio options, therefore the Alliance has extrapolated retirement dates from the ENO Portfolio Stakeholder Case and included these assumptions where appropriate.[i] The Alliance assumed that units whose fuel sources are known to cause substantial pollution would be retired earlier than other fuel types. The extrapolation likely includes assumption errors and is only intended to illustrate portfolio outcomes in *Chapter 9: Plan Results*.

Table 3.1: ENO's MW Capacity Mix as of December 2015

MW	Fuel	Unit	Load Type[1]	Retirement Date (year)
510	CCGT	Union 1	Load Following	
392	Nuclear	WBL[ii]: Arkansas Nuclear One, Grand Gulf, Riverbend[iii]	Base	

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[i] This is the Wholesale Baseload Transaction and includes 6 separate units owned or contracted for by EAI. The units it is comprised of are discussed further below.

112	CCGT	Ninemile 6	Load Following	
32	Coal	WBL: Independence, White Bluff	Base	2028 (White Bluff)
21	Nuclear	Waterford 3 (Algiers)	Base	
13	Legacy Gas	Ninemile 4 (Algiers)	Load Following	2028
13	Legacy Gas	Ninemale 5 (Algiers)	Load Following	2031
10	Legacy Gas	Little Gypsy 3 (Algiers)	Load Following	2027
9	CCGT	Oxy-Taft (Algiers)	All	2018
8	Legacy Gas	Little Gypsy 2 (Algiers)	Load Following	2029
8	Legacy Gas	Waterford 2 (Algiers)	Load Following	2028
7	CCGT	Acadia (Algiers)	Load Following	2032
7	Legacy Gas	Waterford 1 (Algiers)	Load Following	2033
6	CCGT	Ninemile 6 (Algiers)	Load Following	
4	Nuclear	Riverbend (Algiers)	Base	
3	Nuclear	GG (Algiers)	Base	
2	CCGT	Perryville 1 (Algiers)	Load Following	
2	Hydro	Vidalia (Algiers)	Peaking	
1	CT	Perryville 2 (Algiers)	Peaking	2027
1	Oil	Waterford 4 (Algiers)	Peaking	2020
1	CCGT	Sterlington 7 (Algiers)	Peaking	2027
0.4	Hydro	Toledo Bend (Algiers)	Peaking	
0.2	Legacy Gas	Buras 8 (Algiers)	Peaking	2032
1162.6		***TOTAL MW***		***1052.4***

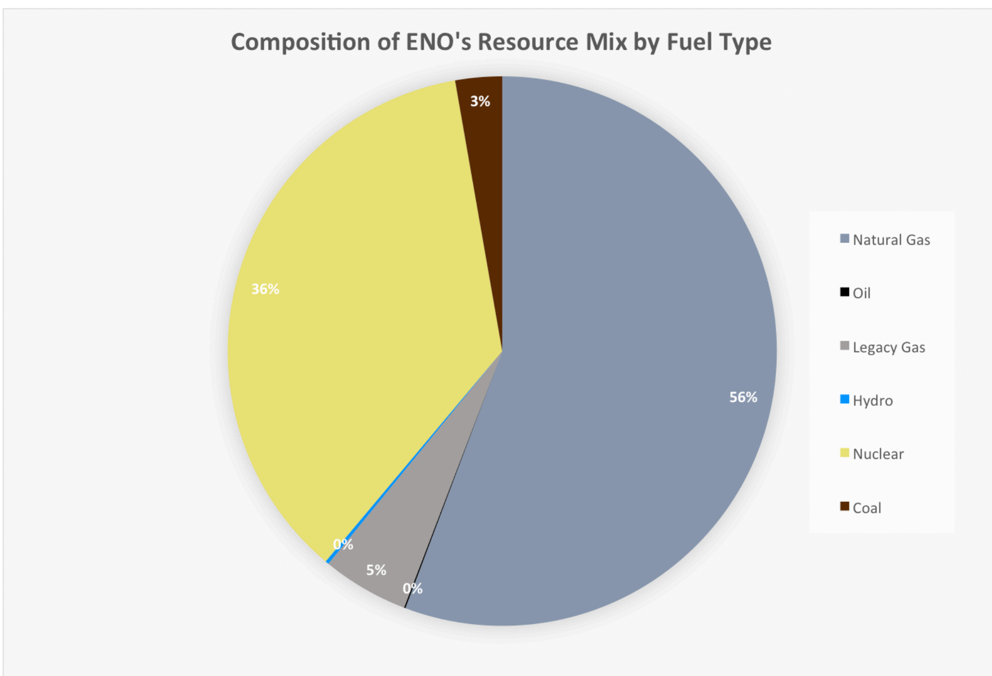
*Note: ENO did not provide specific retirement dates. Dates were extrapolated and may have errors.

[iii] It is unknown at this time how much nuclear power ENO receives from each of the separate units contained here, as the quantities have not been specified by the company. Based on information provided in the ENO's 2012 IRP the best estimate is: 97 MW of capacity from Riverbend, 218 MW from Grand Gulf, and 77 MW from WBL PPA.

Following the decommissioning of Michoud units 2 & 3 and the acquisition of the Algiers supply area, ENO has a current maximum capacity of 1162.6 MW, which falls to 1052.4 MW by 2035. Additionally, with the acquisition of the Algiers supply territory, ENO has increased the number of units from which it receives power from 9 to 25 units.[iv]

Currently, ENO's total capacity is heavily dependent on gas with 56% of its capacity fueled by natural gas, and another 5% fueled by a mixture of gas and oil (referred to as "legacy gas"). The rest of its capacity mix is predominantly made up of nuclear facilities, and a small, but not insignificant portion (3%) is coal. Less than 1% of its resource capacity comes from renewables and the 2.6 MW of hydro included in its capacity mix is the result of the Algiers transfer. A brief description of ENO's top supply resources follows.

Figure 3.1



Units Comprising ENO's Resource Portfolio

[iv] All information regarding the sources of KWh provided to the Algiers service area can be found in ENO's 2015 Final IRP Filing.

Union Power Station Block One

The Union Power Station located near El Dorado, Arkansas entered into commercial service in 2003 and was acquired by Entergy subsidiaries in the Spring of 2016.[2] The power station consists of four combined-cycle gas fired units[3]. Entergy New Orleans acquired one of these units, known as "Power Block One" as part of the acquisition agreement and is anticipating a supply of 510 MW as part of the acquisition.[4]

Table 3.2: Union Power Station Emissions in Metric Tons[5]

Type of GHG	**Metric Tons Emitted**	**ENO Emissions in Metric Tons (25% of units)**
Carbon Dioxide (CO_2)	2,572,925	643,231.25
Methane (CH_4)	1,172	293
Nitrous Oxide (N_2O)	1,397	349.25

These numbers are based on plant reports submitted in 2014 for the entirety of the Union Power Station, of which ENO owns 1/4 of the generating capacity.

Wholesale Baseload (WBL) PPA: Coal and Nuclear Power Contracts

ENO currently receives at least 110 MW sourced from coal and nuclear facilities owned and operated by Entergy Arkansas, Inc. (EAI). The agreement includes the nuclear units Arkansas Nuclear One units 1 and 2, as well as coal units Independence 1 and White Bluff units 1 and 2. The Alliance assumes these units provide the 32 MW of coal capacity contained in the 2015 IRP because ENO offered no details on the source of the coal in its resource mix. It is possible that ENO is also receiving a portion of its 329 MW of nuclear capacity from the WBL PPA as it has reported receiving between 110 and 174 MW of capacity through the PPA in years past.[6,7,8]

<u>Independence 1</u>

Located in Newark, Arkansas Independence Unit 1 is one of two coal fired generation units.[9] Each unit is nameplate-rated at 850 MW. Independence 1 entered into commercial operation in 1983.[10] This is one of the units for which ENO has a life of unit PPA with EAI, and the cost recovery for which was approved by the City Council in R-03-272.[11] Currently, EAI owns 31.5% of the unit.[12]

White Bluff 1 & 2

The White Bluff units are coal fired generators located in Redfield, Arkansas and 57% of each are owned by Entergy Arkansas.[13] White Bluff Unit 1 was brought into commercial operation in 1980, and White Bluff Unit 2 was brought into commercial operation the following year. Each has a reported 466 MW capability.[14] ENO currently has a life of unit PPA with EAI for each of these units, the cost recovery of which was approved by the City Council in resolution R-03-272.[15] In the fall of 2015, EAI proposed to cease operations of the White Bluff facilities by 2028 instead of installing scrubbers, which would be necessary to comply with EPA rules created under the Clean Power Plan.[16]

Table 3.3: Coal Asset Emissions in Metric Tons[17]

Type of GHG	**White Bluff Metric Tons Emitted**	**Independence Metric Tons Emitted**	**ENO Emissions in Metric Tons (1.22 %)**
Carbon Dioxide (CO_2)	10,805,320	10,334,280	257,017.37
Methane (CH_4)	31,221	29,862	742.65
Nitrous Oxide (N_2O)	54,136	51,778	1287.71

Note: These numbers are based on 2014 reported figures for both White Bluff Units and both Independence Units.. Emissions specific to New Orleans was derived by calculating the percent of ENO's WBL contracted MW (32) by the total MW for the coal plant in the contract (2632 MW) and then applying the percent to the total emissions.

Arkansas Nuclear One (ANO) Units 1 & 2[18]

Arkansas Nuclear One Units 1 & 2 are pressurized water nuclear reactors located in Russellville, Arkansas.[19] Unit one came into commercial operation in 1974 and its operating license is set to expire in 2034.[20] Unit two came into commercial operation in 1980 and its operating license is set to expire in 2038.[v] ENO currently has a life of unit PPA with EAI for each of these units, the cost recovery of which was approved by the City Council in resolution R-03-272.

Grand Gulf One[21]

Grand Gulf One is a boiling water nuclear reactor located in Port Gibson, Mississippi.[22] It came into commercial operation in 1985 and has a maximum capacity of 1,266 MW.[23] System Energy Resources, Inc. (SERI) owns 90% of the unit.[24] It completed a system upgrade in June of 2012, making it the largest nuclear reactor in the country and the 5th largest in the world.[25] It's operating license is set to expire in 2024.[4] ENO currently purchases power from Grand Gulf through a PPA with SERI for 17% of the capacity it owns.[26] Capacity from Grand Gulf is also included in the WBL PPA. The cost recovery of each of these was approved by the City Council in R-03-272.

Riverbend

The Riverbend Nuclear Station is a boiling water reactor owned by Entergy Louisiana, LLC.[27] It is located in St. Francisville, LA and has a maximum capacity of 974 MW.[28] This is an increase in capacity from when it came into commercial operation in 1983 due to a facility upgrade the reactor received in 2003.[29] Its operating license is set to expire in 2025.[4]

ENO is currently in a life of unit PPA for Riverbend for one-third of its wholesale capacity.[30] In 2008 and 2012 the capacity reported by ENO from this PPA was 97 MW.[31] The cost recovery of this PPA was approved by City Council Resolution R-03-272.[32]

Waterford 3[33]

The Waterford Steam Electric Station, Unit 3, commonly called Waterford 3, is a combustion engineering two-loop pressurized water reactor. The plant produces 1,218 MW and is located in Killona, Louisiana.[34] The plant went into service on September 24, 1985 and its operational license is set to expire on December 18, 2024.[4] We did not include this date in the retirement field on the chart above because it is our understanding that Entergy will receive a relicensing permit.

[v] The Alliance does not support or oppose the relicensing of Arkansas, Grand Gulf, Riverbend, or Waterford 3 at this point but we reserve the right to support or oppose the relicensing in the future.

Ninemile 6

Ninemile 6 is a Combined Cycle Gas Turbine located in Westwego, Louisiana.[35] It has a maximum capacity of 560 MW and is owned by Entergy Louisiana, LLC.[36] It came into commercial operation in 2014 and was intended to replace Ninemile units 1 and 2.[37] ENO entered into a life of unit PPA for 20% of the unit's capacity. Ninemile 6 also provides an additional 6 MW of capacity through the Algiers transfer.[38]

Table 3.4: Ninemile Power Station Annual Emissions in Metric Tons[39]

Type of GHG	**Metric Tons Emitted**	**ENO Emissions in Metric Tons (15.1%)**
Carbon Dioxide (CO_2)	2,426,907	365769.57
Methane (CH_4)	1,115	16.80
Nitrous Oxide (N_2O)	1,329	20.03

These numbers are based on data reported in 2014. This information is also relevant in evaluating the greenhouse gas emissions of Ninemile 4 & 5, which are now part of ENO's resource mix following the transfer of Algiers.

Table 3.5: Emissions from Resources that Accompany the Algiers Transfer[40]

	Emissions in Metric Tons		
Power Plant	**Carbon**	**Methane**	**Nitrous Oxide**
Buras	3782	2	2
Sterlington	7093	3	4
Perryville	1297216	602	717
Waterford 1 & 2	78077	366	433
Oxy-Taft	2282772	1059	1262
Little Gypsy	909924	422	503
TOTAL	**4578864**	**2454**	**2921**

Existing Supply Alternatives

Current Resource Adequacy

The basis of a long-range plan is a path for meeting load requirements with current and proposed resources. Fulfilling capacity needs in a safe, reliable, affordable, resilient, and environmentally responsible way is of interest to all stakeholders. There is more to filling this need than just power plants, it is also about access to power plants through transmission.

MISO facilitates Resource Adequacy planning through the Organization of MISO States Survey, in which Load Serving Entities (LSE) self-report the upcoming year's forecast capacity requirements and resources. Through resource adequacy planning, MISO has forecasted that the southern region will have capacity in excess of the reserve margin until 2022.[41] Entergy's zones, including 8, 9, and 10 (ENO is in Zone 9) have a surplus of capacity through 2021, putting downward pressure on MISO market costs, and making owning new generation not cost-effective. The nearly 1GW of surplus capacity that will be available to MISO south through 2021 has limitations on exports to the north, reducing the potential that this capacity will be exported to the North/Central region, and increasing energy or capacity costs prematurely.

As discussed in Chapter 3, the 2016 MISO OMS survey states that LSE projections in the MISO system are based on modest load growth, but do not match flat-loads in recent history. This suggests an even longer time horizon for available and cost effective surplus capacity in the MISO market as continuation of flat demand will alleviate projected demands on existing capacity. As Entergy's recent experience with owned generation at Powerblock 1 of the Union Power Station illustrates, incorrect forecasts of customer impacts based on capacity market sales can be an expensive miscalculation for customers.[42] As a result of the mistakes in forecasting, customer rate impacts were triple that of ENO's Union proposal. This is an opportunity for lessons learned when considering ENO forecasting.

Upgrades to Mitigate Michoud Deactivation

In order for Entergy New Orleans to decommission Michoud in 2016, the utility was required to submit an application to MISO.[43] The application requested permission to close the generator ahead of schedule, as the loss of the Michoud affected MISO's dispatchable capacity as well as ENO's access to capacity. In granting permission to decommission Michoud, MISO required transmission upgrades in and to the ENO territory, which cost Entergy New Orleans customers $30 million dollars. Upgrades were approved by the Council and the transmission projects were completed in advance of Michoud's deactivation. Based on MISO's agreement that Michoud could safely close following these upgrades, it appears MISO believes ENO's current access to capacity sited outside Orleans Parish is suitable, alongside the continuing MTEP process of further development and upgrades.

Conclusion

New Orleans' current resource mix is highly dependent on fossil fuels as the city has less than one percent of renewable energy, and the hydro-electricity included in the resource mix was added during the Algiers transfer. The 1 MW solar plant with battery back-up is a good start and this section shows that more sources are available. The Alliance finds that the current supply-side resource mix for New Orleans does not protect ratepayers from severe risks such as fuel price spikes, future GHG regulation, more stringent pollution regulation, and public health factors.

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CHAPTER 4

ADDRESSING EXTERNALIZED COSTS

Overview

Equity, defined as the quality of being fair, cannot be attained when externalized costs are not included in evaluating energy resources. When part of production results in pollution released into the environment, the producer is not paying the full cost of operations. Instead, the cost of pollution is borne, in poor health outcomes and environmental damage, by the public. According to a 2013 United Nations report almost one-third of global corporate profits are derived by shifting the cost of pollution onto individuals through increased public health and environmental costs. Around the world, there is a growing movement to quantify the value of environmental essentials like fresh water, clean air, wetland function, soil fertility, pollinators, and more, in order to properly account for the externalized costs production. In the United States, the effort to control externalized costs is being led by the Environmental Protection Agency whose national regulatory efforts have a local impact.

This section discusses the externalized costs that are incurred by Louisiana taxpayers as a result of ENO's existing resource mix. Additionally, in this section, the Alliance offers a resiliency rubric to begin the conversation about the added value of resiliency when making resource decisions.

Louisiana Faces Legal Battle Over Failure to Address Regional Haze

In 2008, in accordance with the 1990 amendments to the Clean Air Act, Louisiana designed a plan to address regional haze impacting the Breton National Wildlife Area, the only Class 1 area in the state. The Environmental Protection Agency (EPA) partially rejected that plan in 2012, in part because the Department of Environmental Quality failed to properly analyze the use of Best Available Retrofit Technology (BART) for Electricity Generating Units.[1] Since that time, the EPA has yet to accept an alternative state implementation plan, nor has it issued a federal implementation plan of its own. As a result of this inaction, in March of 2015 the Sierra Club filed suit against the EPA to compel agency action.[2]

While there has not been any federal action taken at this point in time, on July 7th of this year the EPA published a proposal to issue a consent decree to the Sierra Club's suit in the Federal Register.[3] Federal action on regional haze that impacts energy generating units in the state could thus be forthcoming.

Mercury and Air Toxics

On December 16, 2011 the EPA issued a final rule to reduce emissions of hazardous air pollutants called the Mercury and Air Toxics Standards (MATS) that apply to power plants with capacities of 25 MW or more whose fuel sources are coal and oil. MATS sets emissions caps for toxins the EPA has identified as causing cancer and other serious health effects including mercury, arsenic, chromium, and nickel, as well as acid gases including hydrochloric acid and hydrofluoric acid.[4] According to the rule, those impacted facilities had four years to meet the announced standards and the deadline for compliance was April of 2016.[5] Before its deactivation, the Michoud generating facility would have been impacted by MATS and was the only Entergy New Orleans facility to have been regulated. However, Independence, White Bluff 1, and White Bluff 2 are coal units in Arkansas that provide the New Orleans area with energy through the WBL PPA and are impacted by the federal regulation.

Greenhouse Gas Emissions and Climate Change

In 2009, the EPA published the Mandatory Greenhouse Gas (GHG) Reporting Rule under the Clean Air Act, which requires utilities to report emission data for all major stationary sources of greenhouse gas emissions, such as power plants. However, Entergy had already been collecting its GHG emission data. In May 2001, Entergy Corporation issued a public commitment to stabilize CO2 emissions from fuel combustion at the company's power plants. The stated goal was to stabilize CO2 emissions from its U.S. power plants at year 2000 levels through 2005 and establish a $25 million Environmental Initiatives Fund (EIF) in support of achieving the 2001-2005 stabilization targets. Ten years later, in 2011 the company renewed its commitment to stabilize GHGs. Entergy's updated GHG reduction commitments are:

- Stabilize CO2 emissions from all Entergy power generation plants plus controllable purchased power at 20% below 2000 levels through 2020.
- Commit funding of $10 million in support of achieving the 2011-2020 target.
- Document activities and annually report progress (latest report was filed March 2015)

- Employ an independent third party organization to verify measurement of Entergy's CO_2 emissions from U.S. power plants

The Alliance applauds Entergy for making this commitment and the IResP prioritizes lower emitting carbon technology in its final recommendations in support of Entergy Corporation's GHG goals. This low emission technology will further benefit Louisiana in its efforts to comply with the EPA's Clean Power Plan.

Quantifying Externalized Costs of GHGs

To estimate the benefits of controlling greenhouse gas emissions, the EPA has established a social cost of carbon. The social cost is meant to capture the economic damages associated with powerful greenhouse gas emissions in a given year. Examples of economic damages from GHGs include declining agricultural productivity, impacts to public health, and property damage from extreme weather events. Unfortunately, the social cost does not include all of the detrimental changes to physical, ecological, and economic structures caused by GHG emissions because the modeling is too imprecise at this time. However, the EPA findings are illustrative of the significant impacts of emissions and were utilized by the Alliance to calculate the low and high social costs of three GHG pollutants in ENO's existing resource mix.[6]

Carbon dioxide is the most common GHG, making up 80% of all GHG emissions. Carbon dioxide is the least potent of the GHG emissions in terms of heat retention in the atmosphere but the molecules stay in the atmosphere for long periods. Electricity generation is the leading emitter of carbon dioxide (37% of CO_2 in the US).[7] The table below illustrates the low to high cost estimates of carbon dioxide pollution in ENO's resource mix.

Table 4.1: Social Cost of Entergy's Carbon Dioxide Emissions

Power Plant	Carbon Dioxide (emissions in metric tons)	Low Cost Carbon Dioxide ($37 per metric ton)	High Cost Carbon Dioxide ($105 per metric ton)
Buras	3,782	$139,934.00	$397,110.00
Sterlington	7,093	$262,441.00	$744,765.00
Perryville	1,297,216	$47,996,992.00	$136,207,680.00
Waterford 1 & 2	78,077	$2,888,849.00	$8,198,085.00
Oxy-Taft	2,282,772	$84,462,564.00	$239,691,060.00
Little Gypsy	909,924	$33,667,188.00	$95,542,020.00

9 Mile	2,426,907	$89,795,559.00	$254,825,235.00
White Bluff	10,805,320	$399,796,840.00	$1,134,558,600.00
Independence	10,334,280	$382,368,360.00	$1,085,099,400.00
Union	2,572,925	$95,198,225.00	$270,157,125.00
TOTAL	**30,718,296**	**$1,136,576,952.00**	**$3,225,421,080.00**

**Source for Low and high price per ton: EPA*

Methane is the second leading GHG, making up about 10% of total GHG emissions. Though the amount of methane released is far less than that of carbon dioxide, methane is much more potent. According to the EPA, "pound for pound, the comparative impact of methane on climate change is more than 25 times greater than CO2 over a 100-year period." Methane comes from biological decomposition, which occurs in wastewater treatment, landfills, and leakage from natural gas pipelines and power plants.[8] The table below illustrates the low to high cost estimates of methane pollution.

Table 4.2: Social Cost of Entergy's Methane Emissions

Power Plant	Methane (emissions in metric ton)	Low Methane ($580 per metric ton)	High Methane ($3500 per metric ton)
Buras	2	$1,160.00	$7,000.00
Sterlington	3	$1,740.00	$10,500.00
Perryville	602	$349,160.00	$2,107,000.00
Waterford 1 & 2	366	$212,280.00	$1,281,000.00
Oxy-Taft	1,059	$614,220.00	$3,706,500.00
Little Gypsy	422	$244,760.00	$1,477,000.00
9 Mile	1,115	$646,700.00	$3,902,500.00
White Bluff	31,221	$18,108,180.00	$109,273,500.00
Independence	29,862	$17,319,960.00	$104,517,000.00
Union	1,172	$679,760.00	$4,102,000.00
TOTAL	**65,824**	**$38,177,920.00**	**$230,384,000.00**

**Source for Low and high price per ton: EPA*

Nitrous oxide makes up about 6% of total GHG emissions. Unfortunately, nitrous oxide is extremely effective at trapping heat in the atmosphere; it is 300 times more potent than carbon dioxide and stays in the atmosphere on average 114 years. Human activities that contribute to nitrous oxide emissions include fossil fuel combustion, wastewater management, and industrial processes.[9] The table below illustrates the low to high cost estimates of nitrous oxide pollution.

Table 4.3: Social Cost of Entergy's Nitrous Oxide Emissions[10,11,12]

Power Plant	Nitrous Oxide (emissions in metric ton)	Low Nitrous Oxide ($3000 per metric ton)	High Nitrous Oxide ($47000 per metric ton)
Buras	2	$6,000.00	$94,000.00
Sterlington	4	$12,000.00	$188,000.00
Perryville	717	$2,151,000.00	$33,699,000.00
Waterford 1 & 2	433	$1,299,000.00	$20,351,000.00
Oxy-Taft	1,262	$3,786,000.00	$59,314,000.00
Little Gypsy	503	$1,509,000.00	$23,641,000.00
9 Mile	1,329	$3,987,000.00	$62,463,000.00
White Bluff	54,136	$162,408,000.00	$2,544,392,000.00
Independence	51,778	$155,334,000.00	$2,433,566,000.00
Union	1,397	$4,191,000.00	$65,659,000.00
TOTAL	**111,561**	**$334,683,000.00**	**$5,243,367,000.00**

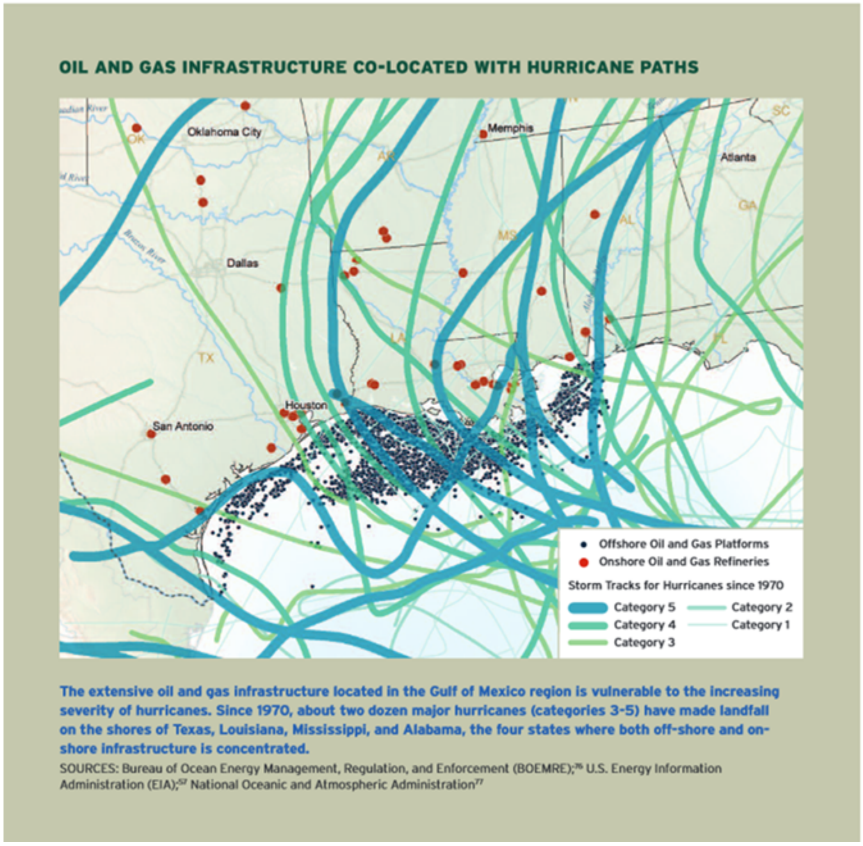
**Source for Low and high price per ton: EPA*

GHG Impacts to New Orleans

The impacts of greenhouse gas emissions on New Orleans likely exceed what is reflected in the social cost findings by the EPA due to its proximity to the ocean, as well as its elevation below sea level. According to the scientific literature, carbon pollution will increase risks for New Orleans by worsening coastal erosion, subsidence, flooding, and hurricane damage.[13] New Orleans, with half its population living below sea level, is extremely vulnerable to these risks.[14]

In addition, climate change will disrupt energy production in the Gulf South, an area that is a top producer of natural gas for the U.S.[15] Extreme weather has already caused severe interruptions in the reliability and resilience of pipelines, power plants, and electricity grids in the region.[16] Figures 4.1 below illustrates the vulnerability of this industry to storm events.

Figure 4.1: Oil and gas infrastructure co-located with hurricane paths



Groundwater and Sinking

Externalized costs of energy production take many forms, and one that has recently come to the forefront of discussions in New Orleans is the use of groundwater. The historic use of groundwater by the former Michoud power plant is related to substantial sinking according to scientists at LSU and NASA. New research shows the land at and around the Michoud Power Plant site has been sinking at a faster rate than the rest of the city.[17] There is strong evidence that groundwater pumping by the Michoud plant is linked with this accelerated subsidence rate, making New Orleans East more vulnerable to flood risk.[18]

Over the last 6 decades, Michoud withdrew approximately 10 million gallons per day on average from the Gonzalez-New Orleans Aquifer using deep wells sunk 631-645 feet below the plant.[19] Since the late 1950s, when the first generating unit was built, the facility has been the single largest user of groundwater in Orleans Parish.[20] Pumping water from aquifers results in a decline in water pressure, diminishing support for clay and silt beds that lay beneath the

Earth's surface. The diminished support allows for these malleable materials to compress causing the surface to sink.

Sinking and subsidence has been shown to degrade critical infrastructure, like levees and roads.[21] It is particularly alarming that scientists have connected the level of subsidence in the area of the Mississippi River Gulf Outlet Canal (to the immediate southeast of Michoud) and the destruction of the levees during Hurricane Katrina which resulted in devastating flooding.[22] At a March 2016 meeting of the Coastal Protection and Restoration Authority of Louisiana, Robert Turner of the Southeast Louisiana Flood Protection Authority described the levee walls between Lake Borgne, New Orleans East, and St. Bernard Parish as "more prone to flooding than before Katrina," and in need of "levee lifts in the near future".[23] The need to raise the levees is indicative of the continued impact of subsidence on the City's infrastructure and safety.

Subsidence that undermines the effectiveness of levees and floodwalls is the most damaging outcome for an already vulnerable population. Continued use of groundwater will likely exacerbate the unnatural subsidence already occurring, leading to increased vulnerability of flooding in New Orleans, especially New Orleans East, the Lower Ninth Ward, and St. Bernard Parish, all of which have large percentages of low-income individuals and children.

The cost of levee failure and subsidence in New Orleans East in the vicinity of the Michoud location is difficult, if not impossible, to quantify because one cannot put a price on culture, family, and well-being.

Nuclear Power

The externalized costs of nuclear power are often unseen by the population at large. Nuclear power does not emit pollutants as a result of combustion but the source material is highly volatile. In a 2011 report by the World Bank, the author identified the social cost of nuclear power to be $52/MWh.[24] ENO's IRP does not show the specific MW or MWh from the nuclear power plants and thus, we cannot calculate the externalized costs of these resources. However, in Louisiana, generating electricity from nuclear energy instead of coal resulted in reductions of 19,000 tons of sulfur dioxide, 12,000 tons of nitrogen oxide and 12 million metric tons of carbon dioxide.[25]

A Resiliency Rubric

The Alliance created a Resiliency Rubric for the purpose of beginning a conversation with the City Council, Advisors, ENO, and the City around the problems New Orleans faces in terms of future costs, environmental justice, and storm risks, among other resiliency concerns, and how the city should determine what resources are best within this context. Below is the criteria the Alliance believes is necessary to evaluate the resiliency of potential resources and an application of the criteria to the existing resource mix. It is the hope of the Alliance that its proposed criteria will prompt a discussion on what resiliency means for the New Orleans energy system.

The criteria includes:

"**Risk of Fuel Spikes**" This means that the generating plant uses a fuel source that is subject to global markets, such as coal, oil, or natural gas. If the plant is a CCGT, CT, legacy gas, or coal plant then the power plant gets a "Yes" for the risk.

"**Environmental Justice Score**" Created by the Alliance for illustrative purposes. The scale is based on a 1 to 4 rating scheme where "1" represents the lowest impact to people living or working within 3 miles from the generating source and "4" represents the highest impact. Renewable energy like hydroelectric received a 1 because there are no air emissions. CCGT plants were given a 2 for having limited emissions at the generating source. Nuclear received a 3 for low probability but extremely high-risk events. Legacy gas and coal were labeled 4 because the air emissions are the most substantial of the power-generating sector. This formula has not been vetted for accuracy or efficacy and is subject to change based on input from the Environmental Justice community and other important stakeholders.

"**Economic Impact to New Orleans**" It is important that local ratepayer dollars be reinvested in New Orleans as much as is possible. A strong economy is an essential part of a resilient city. It is assumed that resources located within Orleans Parish have higher direct and indirect economic impact and job creation but this assumption needs to be analyzed more carefully. A resource scored a "high" if it is located within the parish. "Medium" means the resource is very low cost and thus, benefits ratepayers but does not add tax or job benefits to the parish. "Low" applies to resources that are assumed to have higher costs and no local job benefits. If the cell is blank, then it means that we do not have enough information to make a sound judgment. This metric is only meant to be illustrative.

“**Ability to Provide Emergency Power**” Determines if the power plant is safe from any storm events geographically close to New Orleans. Major infrastructure must shut down prior to being hit by a major hurricane and thus, cannot supply emergency power to the city. For example, Riverbend, Patterson and Michoud all shut down ahead of Hurricane Katrina hitting land. If the power plant is within 15 miles of New Orleans, then it received a “No”, within 30 miles “Maybe”, and beyond 30 miles the power plant received a “Yes”. Buras 8 was labeled “no” because of its proximity to the Gulf of Mexico. Again, this labeling is for illustration purposes only.

“**Offsets Transmission Islanding**” Power units received a yes if location is within 30 miles of New Orleans. It is assumed that transmission lines that connect power plant resources up to 30 miles from the city would retain functionality.

“**Flood Risk**” Criteria is based on the Flood Vulnerability Assessment Map created by the U.S. Energy Information Administration. The map overlays FEMA flood hazard maps with EIA’s critical energy infrastructure. If the power plant is located within a flood zone, then it received a “Yes”.[26]

The criteria in the Resiliency Rubric are not meant to be exclusive, simply illustrative. This is the beginning of a much larger conversation that should include many more stakeholders, including the utility.

Table 4.4: Supply-Side Resource Resiliency Rubric

Unit	Fuel Spikes	EJ Score	Economic Impact	Emergency Power	Offset Islanding	Risk of Flooding
Union 1	yes		medium	yes	no	no
Riverbend	no			yes	no	no
Ninemile 6	yes		medium	no	yes	no
White Bluff	yes			yes	no	no
Waterford 3	no			maybe	yes	yes

Arkansas 1 & 2	no		low	yes	no	yes
Ninemile 4	yes		medium	no	yes	no
Ninemale 5	yes		medium	no	yes	no
Little Gypsy 3	yes		medium	maybe	yes	no
Oxy-Taft	yes		medium	maybe	yes	no
Little Gypsy 2	yes		medium	maybe	yes	no
Waterford 2	yes			maybe	yes	no
Acadia	yes			yes	no	no
Waterford 1	yes			maybe	yes	no
Grand Gulf	no			yes	no	no
Perryville 1	yes			yes	no	no
Vidalia	no			yes	no	no
Perryville 2	yes			yes	no	no
Waterford 4	yes			maybe	yes	no
Sterlington 7	yes			yes	no	yes
Toledo Bend	no			yes	no	no
Buras 8	yes			no	no	yes

Conclusion

There are many reasons to choose clean, renewable sources of energy. Mitigating public health and environmental damage is good business too. There is a clear financial cost to pollution that for most of history have been born by the public at large in increased costs of health and maintenance of property. However, recent decades have seen a shift in public policy to require industry to internalize the cost of pollution by preventing its occurrence in the first place. Wise corporations have begun to incorporate these costs into their business planning and the ratepayers of New Orleans should expect no less from the primary source of their energy.

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CHAPTER 5

On Target: Energy Efficiency and Demand Response

Overview

This section focuses on the value of energy efficiency (EE) and demand response (DR) at the residential, commercial, industrial, and transmission level. The purpose of energy efficiency is to capture energy that is being spent uneconomically. In a home, this could mean that the cool air meant for inside is leaking into the attic causing the home to be warmer than is comfortable and the electric bill to higher than is affordable. In a business striving to lower overhead costs, energy efficiency programs mean more efficient lighting and improved building science. For industrial customers, energy efficiency and demand response programs boost the profit margin by minimizing the cost per unit manufactured. For the utility, energy efficiency may mean optimization of transmission and distribution systems by reducing voltage on lines, or it may mean distributing combined heat and power to fully use the value of burned natural gas. In every aspect of our lives, we are using and possibly wasting energy and this is bad for the economy, the environment, and public health.

Common Sense Leadership: The Council's Vision for Energy Efficiency

In the aftermath of Hurricane Katrina, the New Orleans City Council made energy efficiency a cornerstone of their vision to rebuild New Orleans sustainably. The community benefits from their leadership have been far reaching - reduced energy bills for families and business, improved health and comfort of people's homes, elimination of energy waste and reduction of pollution, all while investing more dollars in the local economy for economic growth and job creation. Not only does energy efficiency offer more community benefit than any other energy resource, it is the lowest cost, most abundant, and most flexible option available to meet New Orleans' future energy needs.

City Council Sets Specific EE Targets

Building on this vision, the New Orleans City Council enacted specific Energy Efficiency targets on December 10th, 2015, in Resolution R-15-599, which read:

> *"WHEREAS, the Council believes it would be reasonable in the development of subsequent Energy Smart Program Years (Program Year 7 and beyond) for the*

Company to incorporate in its Energy Smart and IRP filings for evaluation by the Advisors, Intervenors, and the Council the goal of increasing the projected savings from the Energy Smart program by 0.2% per year, until such time as the program generates kWh savings at a rate equal to 2% of annual kWh sales."[1]

The Alliance analysis suggests that these targets can effectively meet a significant portion of New Orleans' future energy needs while saving customers money.

Significant Energy and Capacity Savings from New Orleans' EERS

The New Orleans City Council called on Entergy New Orleans to increase energy efficiency savings from the Energy Smart programs by 0.2% each year to reach a 2% yearly energy savings goal. The American Council for an Energy Efficient Economy (ACEEE)[i] estimates this level of energy efficiency savings, as part of an overall demand-side management portfolio that includes both energy efficiency and demand response programs, can lead to savings of 54-87[ii] MW of peak demand resources by 2020, 141-227 MW by 2025, 216-348 MW by 2030, and 275-443 MW by 2035 (note that these are "at-generation" levels, grossed up for reserve margin and line losses). The savings estimates within each range depends on the level of focus on peak reduction measures through energy efficiency programs that yield relatively high peak demand savings and the utilization of demand response programs.

Table 6.1: EERS Savings Impact

	2020	2025	2030	2035
Council EERS Target %	1.3%	2%	2%	2%
ENO previous year's sales forecast (GWh)	5,643	5,913	6,201	6,497
Sales forecast modified for EE impacts (GWh)	5,405	5,280	5,220	5,226

[i] The American Council for an Energy-Efficient Economy (ACEEE), is a nationally recognized organization that conducts in-depth technical and policy analyses and advises policymakers about energy efficiency policies, programs, technologies, investments, and behaviors.

[ii] This range represent the ratio of MW / GWh achieved by the Energy Smart program on a low range (0.19) and the ratio achieved by Entergy Arkansas on the upper range (0.31). Energy Smart programs have historically not included demand response programs while Entergy Arkansas does utilize such programs.

Incremental annual DSM savings (GWh)	72	106	104	105
Total annual (cumulative) DSM electricity savings (GWh)	249	647	991	1262
Estimated peak demand savings				
Energy efficiency savings (% of all peak savings)	58%	59%	63%	63%
Demand response savings (% of all peak savings)	42%	41%	37%	37%
Estimated peak demand savings, at site				
Energy efficiency (MW)	36	95	156	208
Demand response (MW)	26	66	91	106
Peak demand savings, at generation (MW)				
Energy efficiency (MW)	41	108	178	238
Demand response (MW)	29	76	104	121
Total MW Saved	**70**	**184**	**282**	**359**

Peak Shaving and Modeling DSM Against the Resource it Replaces

A focus on peak load reductions requires a broader examination of both demand response programs as well as energy efficiency programs that target peak load. For example, improving the thermal performance of building envelopes reduces cooling demands and high efficiency air conditioning equipment and systems that serve building cooling loads use less energy and peak power. Additional demand response programs could include commercial load control programs (in addition to dynamic pricing), as well as pool pump programs.

The entire DSM portfolio should be compared to supply-side resource needs, even if some individual programs are not separately cost-effective. It is important to consider the portfolio in its entirety when evaluating cost-effectiveness. For example, programs such as comprehensive retrofit programs or pilot programs may not be immediately cost-effective when examined as a stand-alone program. However, when they are included in a multi-program portfolio the substantial cost savings from the other programs may offset the more limited. Also, the programmatic infrastructure such as marketing, quality contractor, trade allies, and more, can be leveraged throughout the portfolio of programs to create economies of scale. Additionally, the full range of energy efficiency benefits should be considered when evaluating the DSM resource, including peak reduction, off-peak fuel savings, and emissions reductions.

Energy efficiency and demand response provide cost-effective solutions to New Orleans' energy and capacity needs that also keep local dollars in the local economy without needing to import additional natural gas from outside of the city. DSM also buys time for decision making on new resource additions by at least deferring the need for new capacity, or reducing the amount of capacity needed from more expensive new supply.

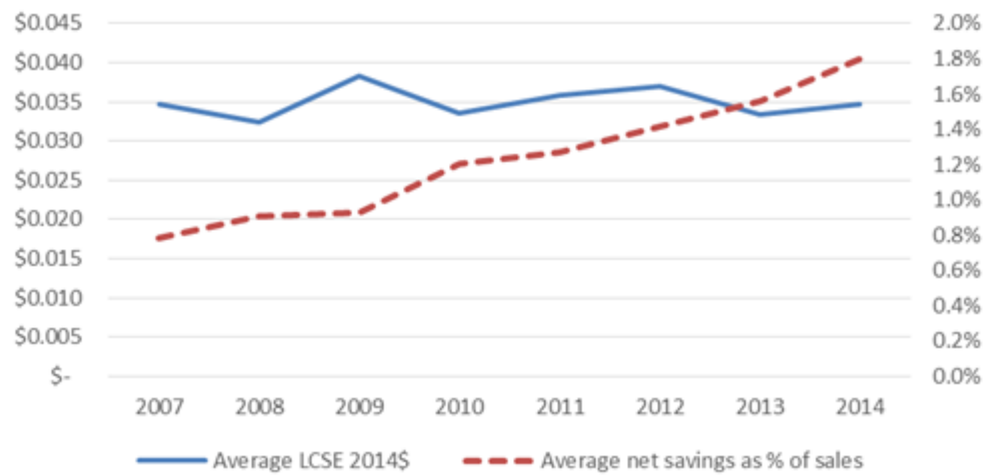
The Council's EERS is Achievable, Cost Effective, and a Boon to the Local Economy

Recent research by ACEEE demonstrates that the City Council's recommended targets and schedule to ramp up to 2% over several years are realistic and achievable. The April 2016 ACEEE study "*Big Savers: Experiences and Recent History of Program Administrators Achieving High Levels of Electric Savings*" identified eight utilities or program administrators from around the country that in recent years have successfully ramped up to 1.5% net annual electricity savings by 2014, four of which ramped up to over 2% per year by 2014. Several of these utilities increased their savings by 0.5% per year, which demonstrates that a ramp up schedule of 0.2% savings per year is achievable.[2]

Arkansas was one of the first southern states to approve utility scale energy efficiency programs. To understand the benefit of these programs, the Arkansas Advanced Energy Foundation commissioned a study in 2014. The utility energy efficiency programs generated an estimated 9,000 jobs and $1 billion in sales.[3] The jobs created average more than $20.00 per hour for skilled labor and boosted locally owned, small businesses within the energy efficiency sector.[4]

Beyond the multiplier effect generated by energy efficiency investments, there is broad consensus that energy efficiency as a utility resource is highly cost-effective. The utility's levelized cost of saved energy (LCSE) is an important metric because it allows utilities and regulators to compare the cost for utilities to administer energy efficiency programs to supply-side alternatives. ACEEE found that for a set of fourteen different utilities or program administrators, which have all reached annual net savings of at least 1.25%, portfolios were highly cost effective, with an average LCSE to the utility of 3.4 cents per kilowatt-hour (kWh) for the portfolios as a whole.[5] Moreover, the LCSE was flat over the study time period (2007-2014) even while total program spending and average spending per customer increased for most observations in the study. The figure below shows the average LCSE and savings as a percentage of sales between 2007 and 2014.

Figure 6.1: Average Cost of Demand Side Management



New Orleans' Policy Successes Prove Cost Effectiveness of Energy Efficiency

The legislative history for energy efficiency in New Orleans points clearly towards the Council's desire to build on its current programmatic success by expanding investment in energy efficiency. Ultimately, the Council aims for New Orleans to be recognized as an energy efficiency leader through the unique independent regulatory authority retained by the Council.

This independent regulatory authority of the City Council allowed it to create Energy Smart as the mechanism to realize its energy efficiency vision and to tie the program to the Integrated Resource Planning (IRP) process. Since it's creation, Energy Smart has saved over 93 Million kWh, worth an estimated $81.7 Million,[iii] while shaving total peak load.[6] Energy Efficiency (EE) and Demand Side Management (DSM) have received virtually universal community support at every public meeting on the subject. Energy Smart has not only received multiple awards from the EPA, but the efforts of New Orleans have contributed critical momentum to the spread of utility-scale DSM programs across Louisiana and Mississippi. At the heart of the matter, the New Orleans City Council has designated energy efficiency as an energy resource that can offset the need for more expensive supply resources. Ultimately, these smart policy decisions will save ratepayers more dollars by avoiding more expensive generation resources.

Table 6.2: Energy Smart Results from Program Years 1-5

	kWh savings	**Estimated Program Year Savings (in USD)**	**CO2 Avoided in Program Year (in lbs)**	**Projected Lifetime Savings (in USD)**	**Projected Lifetime CO2 Avoided (in lbs)**
Residential Program	45,237,738	$4,795,200	253,331,335	$47,952,002	2,533,313,354
Small Commercial	13,266,091	$928,626	74,290,108	$9,286,263	742,901,078
Large Commercial Industrial	34,947,780	$2,446,344	195,707,569	$24,463,446	1,957,075,690
TOTAL	***93,451,609***	***$8,170,171***	***523,329,012***	***$81,701,711***	***5,233,290,122***

*Note Program savings is derived from the cost per kWh for each rate class. Measures assumed to have 10-year life.

Aiming Higher

These initial efforts at enhanced energy efficiency in New Orleans, though important, are just the beginning. There remains a great deal of opportunity to capitalize on low cost energy efficiency resources.

New Orleans has long been the bright spot for Louisiana on efficiency, raising the state's score in national rankings and affording the City recognition as a regional leader. Despite these accolades, Louisiana as a whole remains stubbornly near the bottom of annual national rankings

[iii] In addition to the Energy Smart utility customer efficiency programs, New Orleans has also invested in LED streetlight upgrades.

for energy efficiency.[7] On utility efficiency programs specifically Louisiana ranks slightly better at number 38. At the local level, New Orleans ranks a disappointing 47 out of 51 cities, while receiving just 1.5 points out of 18 for its energy and water utility policies.

To capture the significant EE opportunities and boost New Orleans ranking, ACEEE provided the City Council with a recommended set of proven successful policies in a 2013 analysis of the city's energy efficiency potential entitled, "New Orleans' Efficient Path to 2030: Leadership to Save Energy, Lower Bills, and Create Jobs." Of ACEEE's recommendations, the Council's recent adoption of specific energy savings targets and initial steps toward decoupling have the greatest potential to advance the Council's efficiency and demand side management vision. As demonstrated by ACEEE's new analysis of the Council's energy savings targets, the findings from their previous 2013 report are consistent with the Council's current goals and affirm the feasibility of meeting the majority of New Orleans future energy needs using efficiency and demand side management. Other policy options that will help the Council achieve the most economic use of energy efficiency include:

- Efficiency programs for natural gas and water end uses.
- Expansion of comprehensive, performance based programs.
- On bill financing programs to expand access to capital.
- Increase benchmarking and disclosure requirements to drive demand for efficiency services through improved building energy information.

In addition, ACEEE provided policy recommendations to the City of New Orleans that will help achieve the projected savings.

- Improve implementation of building energy codes and utility program support for code implementation.
- Expand "lead by example" action for energy savings in government operations.
- Use regulatory mechanisms to encourage development of new CHP systems and implement customer incentives to encourage connections to high-efficiency district energy systems

Demand Response

Demand response (DR) is a broad term for a list of methods that use technology, behavior, and even policy, to control peak load and maintain balance within a grid system. DR programming has effectively reduced the need for thousands of MW of installed capacity since the 1970s[8], as utilities, customers, and system operators find value in reducing demand, which in-turn reduces the relative cost of power. By reducing needs from the user-side, newly constructed generating resources can be deferred, as they are altogether not needed. The goal of DR is not necessarily to reduce kWh energy use, but instead to reduce costs and capacity needs by avoiding high demand altogether.

Traditional fossil fuel peaking generators are the most expensive resources per kWh, as they use fuel less efficiently than baseload or load following resources, so less energy is created as a result of burning the fuel, while more emissions per kWh are emitted. Demand response is an alternative that can meet load and capacity requirements without burning anything at all. While natural gas-fired peaking resources are relatively inexpensive for up-front installation, the actual cost to consumers per kWh is much greater, as they only generate electricity a small percentage of the year and otherwise sit unused. Demand response is a more cost-effective alternative as simply curtailing load require relatively small capital investments. Costs for DR may include software, advanced metering infrastructure, and incentives for participation, rather than newly built power plant and transmission. In fact, demand response benefits transmission and distribution systems by reducing congestion, improving reliability, and generally reducing costs of operating grids. While a newly built power plant will also require annual operating and maintenance, DR actually reduces O&M costs. Depending on technology needed, DR programs can be deployed quickly, with program lead times around 1 year. Customer participation may be improved by pairing price and quantity based programs (described below) and continued program support by the utility.

Price or Quantity

Demand response programs can generally be broken into two categories: quantity based or price based. Quantity based programs work by giving the utility the direct control of load through devices installed on HVAC, hot water heaters, and pool pumps. Interruptible load or curtailment (generally for industrial customers) is also included in quantity based programs as the utility makes the decision regarding time and size of load adjustment. Alternatively, price based programs like Time of Use, Critical Peak Pricing, and Real Time Pricing seek to reduce peak use by using price-signals to encourage customer-initiated behavioral changes. Price-based DR programs mean end-users experience prices more like the actual electricity markets. These programs require Advanced Metering Infrastructure (AMI) in order to calculate how customers are responding to price signals and then bill accordingly. Price-based programs have shown to save an average of household electricity savings of around 9%[9]. When paired, quality-based and price-based programs can save customers even more, as a price signal that increases rates when electricity markets are expensive will encourage participation in quantity-based direct load control programs in order to more easily avoid bill impacts.

Current program

Entergy New Orleans has created and is currently implementing a non-AMI enabled Demand Response program in the summer of 2016, with a AC/direct load control (DLC) pilot program, offering 130 households an opportunity to reduce their demand by giving the utility access to and control of their HVAC condenser units. By cycling AC systems off during peak cooling hours, the utility will reduce their total need without any customer required effort. These demand reductions are real and significant. A study conducted by the Brattle Group for the Texas Public Service Commission showed that AC load control programs could be expected to reduce load between 0.8-1.5 kW during a DR event[10]. Direct load control programs are some of the most reliable DR resources available and have a long and verified history as a peak resource. Entergy Arkansas currently has a robust AC/DLC program that reduces peak demand for residential customers.

For pricing-based measures ENO has modeled dynamic pricing programs and has expressed interest in implementing these following installation of Entergy-wide AMI systems. According to ICF modeling for ENO, dynamic pricing for the residential class has the potential to reduce peak demand by between 11-27.5%. Non-residential dynamic pricing has even greater potential for peak demand reduction, especially when paired with interruptible rates. According to calculations using ICF modeling for ENO, peak load reductions using commercial interruptible rates could range from 46-136 MW based on participation rates from 10-30%.

Previous ENO DR pilots

In 2011 and 2012, with support from American Recovery Act funding, ENO implemented an AMI pilot program, that included peak-time rebates, air conditioning load controls, and enabling technologies to reduce electricity usage and peak demands. The program was popular with participants[11] with as great as 96% approval rating on measures. Pilot participants were particularly satisfied with peak-time rebates, which incentivized customers to reduce their household load in exchange for rebates. While some of the technology was new, and there were some difficulties with the pilot, what ENO discovered, and in fact received Smart Grid awards for, was positive customer engagement, and participant retention, with only 11% of participants opting out within the 10 months of the program. Entergy New Orleans customers have proven their interest in programs that can save both money and energy.

Potential Programs:

Pool Pump

While ENO modeled and included pool pumps in their DSM profiles, these pool pumps were simply "efficient." By considering only variable-speed pumps, significant value is ignored. Pool pump Direct Load Control programs can offer energy savings for customers and help meet peak load requirements. Pools can account for 20% of energy used in residential homes, as a single pool pump typically draws around .5 kW, and may draw as much as 1.9 kW. Reducing this load from pool pumps through direct controlled cycling does not affect consumers experience and simply reduces some of the need for peaking resources.[12]

Hot Water Heaters

Utilizing water heaters as a utility demand response resource has great potential to impact peak demand requirements and can be profitable for utilities. Examples of this can be seen across the country (Austin Energy, Florida Power and Light, AEP Ohio, along with a range of Co-operative utilities)) and has been proven to be effective. Direct load control programs for electric water heaters provide significant peak demand reductions while allowing customers the ability to use existing electric water heating equipment, with minimal customer impact. The initial cost of implementing this type of program would be the cost of control switches and their installation. Rate or one-time incentives for customers are additional potential costs. Off-peak electric water heating programs have the potential to provide significant peak demand reductions as well as creating a higher demand for off-peak renewable energy generation. A hot-water peak shaving program in Minnesota had 37,800 participating customers and reduced peak demand by 20 MW for the 4-8 hours when curtailment was needed.[13] Entergy has also included a Hot Water Heating measure in DSM modeling, but as with the pool pump program, the measure fell short of capturing maximum value for the utility and customer by not including a demand response element.

MISO market place opportunity

National potential for peak load reduction using DR is significant, and transmission operators value this capacity. The MISO Capacity market offers an opportunity to sell Demand Response as a capacity resource, as DR receives credit toward resource adequacy requirements. MISO has developed market mechanisms to allow DR to engage in all markets by creating multiple DR categories. One program reduces loads whose values to end-use customers are less than the costs of serving those loads, called Economic Demand Response. Another, Operating Reserve Demand Response, provides regulation or contingency reserves. Emergency Demand Response, or EDR, reduces demand during system emergencies, and finally, Planning Resources Demand Response substitutes for generating capacity. According to MISO's 2016-2017 resource auction results, DR accounts for 5,819 megawatts of capacity and another 3,462 megawatts of behind-the-meter resources are also used for demand response.[14] As reserves tighten into the future, the value of DR for an LSE increases, especially in a constrained region like Downstream of Gypsy and Amite South.

Figure 6.2. FERC Potential Peak Reduction from US ISO/RTO Demand Response Programs

RTO/ISO	Potential Peak Reduction (MW)	Percent of Peak Demand
California ISO (CAISO)	2,180	4.8%
Electric Reliability Council of Texas (ERCOT)	1,950	2.9%
ISO New England, Inc. (ISO-NE)	2,100	7.7%
Midcontinent Independent System Operator (MISO)	9,797	10.2%
New York Independant System Operator (NYISO)	1,307	3.8%
PJM Interconnection, LLC (PJM)	9,901	6.3%
Southwest Power Pool, Inc. (SPP)	1,563	3.5%
Total ISO/RTO	**28,798**	**6.1%**

Source: NRECA.coop, Adapted from Assessment of Demand Response and Advanced Metering, FERC, December 2014.

Transmission Efficiency: Volt Var Optimization

Conservation Voltage Reduction

American National Standards Institute (ANSI) standards require voltage at individual meters to range between 114-126 volts at all times and between 106-127 volts for short periods. An enormous opportunity for savings lies within the allowed range. Voltage and Var Optimization uses data and hardware to optimize voltage flow to reduce line losses, increase efficiency at the end user, and optimize the use of transmission and distribution grids.

Conservation Voltage Reduction (CVR) analyzes voltages on distribution feeders to find ways to reduce voltages while maintaining required ANSI levels that allow systems to operate normally. The result is reduced line losses, peak load reduction, and customer savings without any change to the end user's experience. Based on midrange assumptions, ACEEE estimates that voltage control could reduce American electricity consumption by 2.1% by 2030.[15]

In November 2012, the National Association of Regulatory Utility Commissioners (NARUC) released a resolution stating their broad support for swift deployment of Volt-Var Optimization. Recognizing the potential cost savings and emissions reductions, NARUC encouraged utilities, regulators, and state agencies to work together to remove any barriers to the adoption of Volt-Var Optimization technology. The resolution specifically noted the immediate, predicatable, and measureable benefits to the grid.[16]

With VVO technology employed, energy and demand savings are roughly the same, and the generally accepted correlation between voltage reduction (kv) and consumption or demand reduction is near 1:1. This means voltage decreased by 1 kV can be expected to reduce demand by nearly 1%. One method of reduction is reducing substation voltage for 4-5 hours during a peak event, then restoring original voltage level. Alternatively, voltage reduction can be sustained long-term for general energy savings. Analysis must be done on a circuit in order to determine potential for reductions, as factors such as circuit length affect the potential. Shorter circuit lines result in higher potentials as proper ASNI voltage must be sustained to the end customer.[17] Circuits with high load densities typically result in higher cost-benefit ratios.

Conservation voltage reduction has been implemented across the country since the 1970s. In recent years more utilities have adopted voltage reduction along with other distribution/transmission optimization to reduce line losses and generally manage peak capacity. Updates to distribution systems including smart meters have created new opportunities to conserve energy and reduce demand. While smart meters are not required for CVR, some utilities are recognizing cost savings by implementing CVR technologies as AMI technology is installed. Software development now offers savings validation, which aids in verification of savings for energy efficiency programming.[18] Studies conducted in 2009 by the Northwest Energy Efficiency Alliance (NEEA)[19] found an average energy savings potential of 2.07% using voltage control. Customers reportedly did not notice any difference when voltage is maintained above minimum thresholds.

A project called Green Circuits[20] conducted in 2011 by the Electric Power Research Institute (EPRI) studied circuits on 22 utilities, concentrating in the Southeast. Median reduction in energy use across circuits in the study was 2.34%, with upper and lower quartiles from 3.13% - 1.69%. Virginia's Dominion Energy's utilization of software and smart meters currently achieves an average of 2.9% consumption savings year-round on circuits using CVR. According to Dominion, the use of CVR is particularly valuable in stabilizing voltage in circuits with high penetration of rooftop solar systems.

Peak load decreases are particularly valuable for both energy cost savings and deferring new generation. Peak load reductions show similar savings to energy on a percentage basis, with PNNL reductions in peak load between 0.5-3%, with load reductions achieved at comparable percentage terms. Baltimore Gas & Electric estimates that CVR used over its entire system could lower peak demand by 85MW. Avista (supplying Spokane, WA) is implementing CVR on 72 of its 350 feeders and expects to reduce their load (kW) around 1.86%.[21] Summertime peak demand in New Orleans is of particular interest, and according to NEEA's 2009 work, CVR is most valuable in hot summer conditions when loads are driven by air conditioning, as electric heating is less responsive to CVR savings.

According to the studies conducted in 2011 and reported in Green Circuits, all cases analyzed extensively were economically viable with cost benefit ratios exceeding 3.4 and all with levelized costs of less than $0.03 per kWh. The 6 circuits evaluated compared various improvement options including basic voltage regulation, phase balancing, var optimization, and re-conductoring. Each improvement offered savings, with voltage reduction allowing the greatest savings.

Additionally, voltage reduction may be a welcome service for owners of HVAC systems and other types of machinery, which work more efficiently at lower voltages. Reducing voltages has shown to extend the life of certain machine types, offering customer benefits beyond kwh savings.

A DOE funded study by the National Rural Electric Cooperative Association describes various measures for voltage optimization,[22] including voltage regulators, improved measurement and control systems, and capacitor banks, along with transformer upgrades and re-conductoring. Peak demand reduction was the CVR benefit with the most impressive payback in NRECA's 2014 study. So while CVR is a valuable tool for energy savings, cost to benefit ratios are especially high when considering expensive peaking energy costs.

Conclusion

Energy is wasted at every level of creation, transportation, and use. By utilizing comprehensive energy efficiency programs, New Orleans' can meet its needs in an affordable, safe, and reliable way. Both price and quantity based programs offer value and peak load reductions, which in turn reduce generation needs, costs to consumers, emissions, and other risks associated with traditional generation. Economic development and job creation are boosted most by these resource investments. Energy efficiency is a clear winner in every respect.

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CHAPTER 6

FREE FUEL RESOURCES AND SUPPLY ALTERNATIVES

Overview

New Orleans has significant new opportunities for meeting energy needs that have been overlooked, downplayed, or inaccurately represented in ENO's IRP filings. For example, declining capital costs have driven unprecedented growth in utility scale renewable energy, there is a largely undiscussed, abundant, and untapped combined heat and power potential in Louisiana, such as in sewage treatment plants, and finally, there exists an active marketplace for power purchase agreements. Each of these resource options increase the ability for the City Council to fulfill its clean energy goals, increase resilience, keep rates and bills low by being fuel free resources, and minimize the risk of fuel price spikes.

The Integrated Resilience Plan attempts to solve three problems identified by the City Council, their Advisors, and ENO during the 2015 IRP process:

- Meet gaps in peak demand and maintain a 12% reserve margin;
- Protect the city from transmission islanding during and after storms; and
- Maximize community social and economic benefit, while minimizing pollution and negative health effects.

This section analyzes multiple free fuel generating resources as well as alternative supply options like industrial CHP, capacity markets, transmission, and distributed generation resources that can solve all three problems at competitive costs to customers.

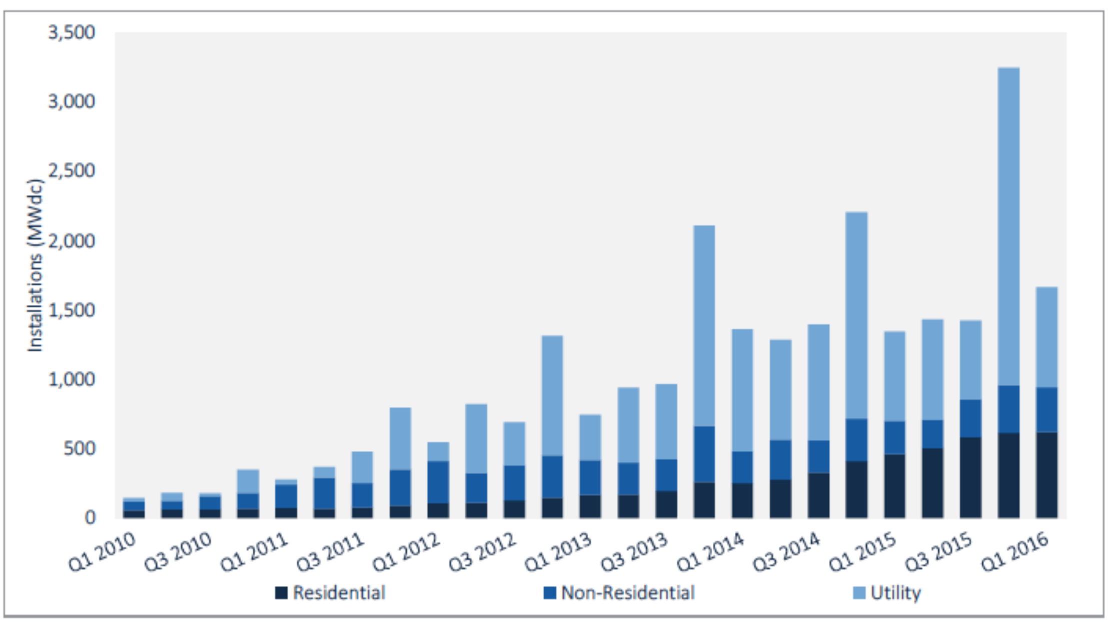
Free Fuel Resource: Utility Scale Solar

The cost of utility-scale solar has fallen precipitously in recent years, faster than any other major energy resource by far, resulting in record levels of new capacity installations. Since 2007, the generation-weighted average PPA cost of solar PV has fallen from \$200 / MWh to less than \$50 / MWh.[1] As prices have fallen, utility solar has moved from virtual non-existence to the *most highly demanded resource* in the nation, with new capacity installations surpassing both natural gas and wind in 2015. The city of New Orleans has already strongly embraced solar PV in the years since Hurricane Katrina, becoming one of the nation's top 10 cities for residential rooftop solar. The City Council has been a vocal and frequent supporter of solar, consistently affirming their desire to see solar power take an even greater role in serving the energy needs of the city going forward. In light of the state's residential solar tax credit expiration, the most compelling area of growth is at the utility scale. With the combination of steep declines in soft costs and PV panel prices, highly attractive federal tax incentives, and a growing roster of recent successful cost competitive major utility acquisitions (including in the Southeast and Entergy utilities), the time has never been better for New Orleans to invest in large scale solar generation.

Installations Double Annually

Since 2013, the total amount of utility owned solar across the country has essentially *doubled each year*. In 2014 new capacity installations totaled more than 3.2 GW, exceeding the 3 GW total from all previous years *combined*. Another 7.5 GW were added in 2015 and current projections are for another 14.5 GW to be installed in 2016 (based on installations to date and projects currently in the queue). Previously rooftop solar was the major driver for new capacity, however since 2012 utility solar has consistently dominated the industry. When rooftop and utility solar are combined, there are now more than 1 million operating solar PV installations in the United States representing 27.5 GW(dc) of total installed capacity.[2]

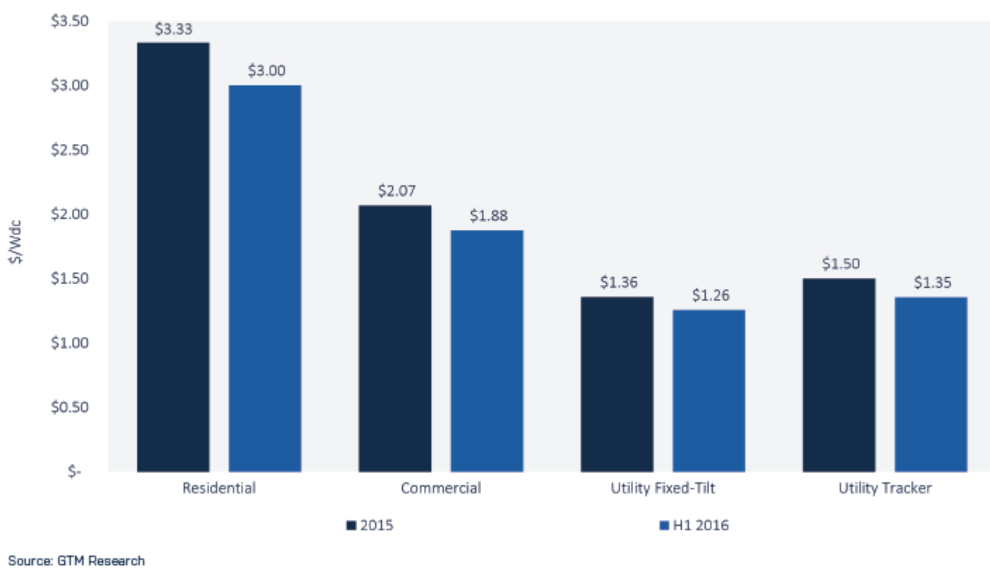
Figure 6.1: Annual US Solar PV Installations Q1 2010 – Q 2016



Source: GTM Research

The rapidity of price declines has resulted in the inclusion of cost figures in major industry reports, which are already out of date by the time of publication. In September 2015, the Lawrence Berkeley National Laboratory published their report "Utility-Scale Solar 2015" which noted that the median price for utility-scale PV was $2.3 / watt (dc).[1] The most recent industry data is from GTM Research in their US Solar PV Price Brief H1, which reports the installed cost of utility scale solar for the first half of 2016 was $1.26 / watt for fixed-tilt and $1.35 / watt for single-axis tracking systems.[3] Reaching the DOE SunShot target of $1.00 / watt by 2020 appears increasingly likely, although it was seen as a lofty goal in recent history.

Figure 6.2: US PV Systems Pricing $/MW

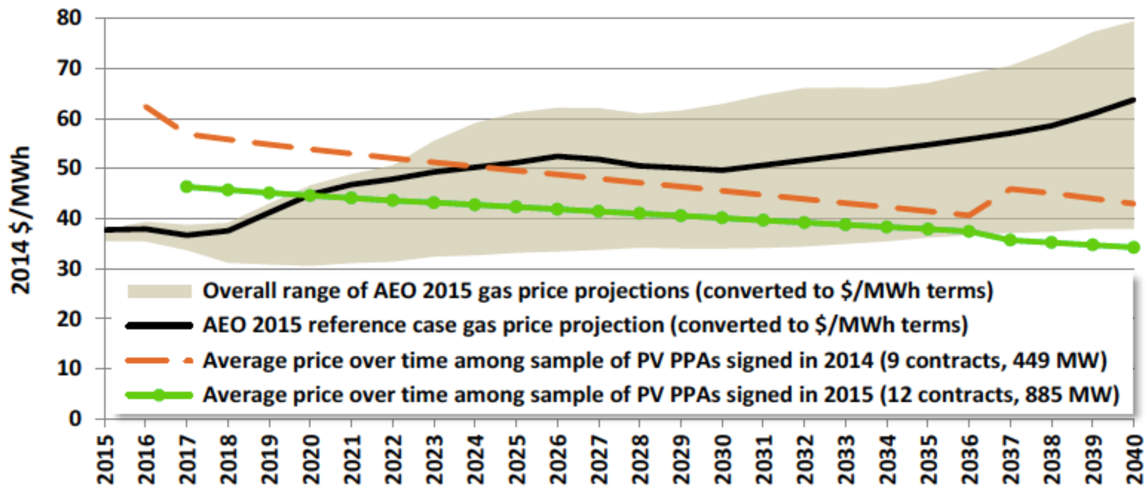


Low Cost Solar PPA

The falling costs of utility solar are leading to historically low PPA prices as well. GTM research shows prices between $35 / MWh and $50 / MWh.[4] Even in 2014, Solar PV PPA prices in the Southwest were reaching $40 / MWh, which is competitive to natural gas fuel prices alone (i.e., even at current low fuel prices and ignoring the fixed capital costs of natural gas-fired generation), making solar a valuable hedge against possible future increases in natural gas fuel prices.[5]

[1] Unless otherwise notes, all installed cost prices per watt are (dc)

Figure 6.3: Average PV PPA Prices and Natural Gas Fuel Cost Projections Over Time[6]



While economies of scale throughout the global marketplace have driven the steep declines in prices noted above, a 30% federal Investment Tax Credit (ITC) in place since 2006 has been another key factor behind the uptick in demand for solar PV by utilities. In December 2015, Congress passed an omnibus spending bill that included a multiyear extension for the ITC, a move that GTM research describes as "the most important policy development for U.S. solar in almost a decade."[7] Previously set to expire in 2016, last year's renewal of the ITC has extended the 30% credit for projects that commence construction through 2019, before gradually declining each year down to 10% after 2023. With this policy certainty, GTM Research projects "solar is expected to account for more than 6% of operating electric generating capacity by 2021, compared to just 0.3% at the beginning of this decade.

According to GTM Research, the implications for the Southeast are significant:

> *"Most notably in the southeast, states where operating solar capacity stands at or below 10 MWdc will increase their capacity by more than tenfold due to inexpensive utility PV power-purchase agreements (PPAs) that reflect the ability of utility-scale solar to both compete with and complement new natural gas plants."*[8]

Successful Examples from Southeast Jurisdictions

Historically, utility solar projects have been overwhelmingly concentrated in the Southwest, but the low price points achieved in recent years are producing an uptick in geographic dispersion across the country.[9] At the end of 2014, 10% of solar capacity in the queues were in the Southeast.

Stakeholders in Entergy Arkansas' IRP proceeding noted that EAI recently entered into a PPA for 81 MW of utility solar with the Stuttgart project. About the PPA Mark Bollinger of The Lawrence Berkeley National Laboratory stated: "[w]hile the exact price of that PPA have not been publicly disclosed, statements made in hearings suggest the price is slightly above $50 / MW, and that the price is below EAI's avoided costs for energy over the term of the PPA"[10]

Austin is another example of highly cost effective solar resources being identified through PPA RFPs. In 2015, Austin Energy issued an RFP for 600 MW of new solar power. The response was overwhelming and impressive. Thirty-three bidders, 149 unique proposals totaling 7,976 MW (more than 13 times coverage), and almost 1,300 MW were reportedly bid at levelized prices of $45/MWh or less.[11]

Resilience Benefits of Utility Scale Solar

Solar energy provides service benefits beyond capacity. For instance, solar energy is an excellent load following resource because it provides low cost energy during high demand daytime hours. Additionally, there is no combustion, no burning, no emissions associated with solar energy, hence, it eliminates the harmful effects on health and the environment associated with pollution from fossil fuel burning plants. Finally, because sunlight is free, solar energy is a hedge against market volatility in input prices, such as fuel, for the lifetime of the unit.[12] On fuel price hedging, NREL notes that PPA prices remain stable with increased financial benefits over time:

> *"More than two-thirds of the PV contracts in the sample feature pricing that does not escalate in nominal dollars over the life of the contract – which means that **pricing actually declines over time in real dollar terms**."*[13]

Community Solar

Community Solar is a term that describes a situation where utility customers share a solar resource instead of investing in a single rooftop system. The solar project may be geographically close to the users but it does not have to be.

As of 2015, 90 Community Solar projects with a total capacity of 80MW have been developed in the U.S.[14] The reason for its popularity is cost. Customers who rent or cannot afford to install solar on their own find that buying into a shared resource is financially attainable. NREL reports that if policy were to favor community solar, cumulative deployment of the resource could top 11 GW by 2020.[15] Policies that support different Community Solar models include:

- **Utility Model:** utility builds project, operates it, and offers subscriptions to customers
- **Special Purpose Entity (SPE) Model:** a business builds project with private investors
- **Non-Profit Model**: charitable nonprofit builds the projects with donated funds

To support Community Solar in New Orleans, the City Council would need to adopt a resolution choosing the right model for New Orleans and then clarifying specific points. Among the issues to decide are how costs and benefits are allocated between the builder and the subscribers, how taxes will be treated for the energy purchased, addressing any securities regulation, and other questions.

Free Fuel Resource: Wind Power

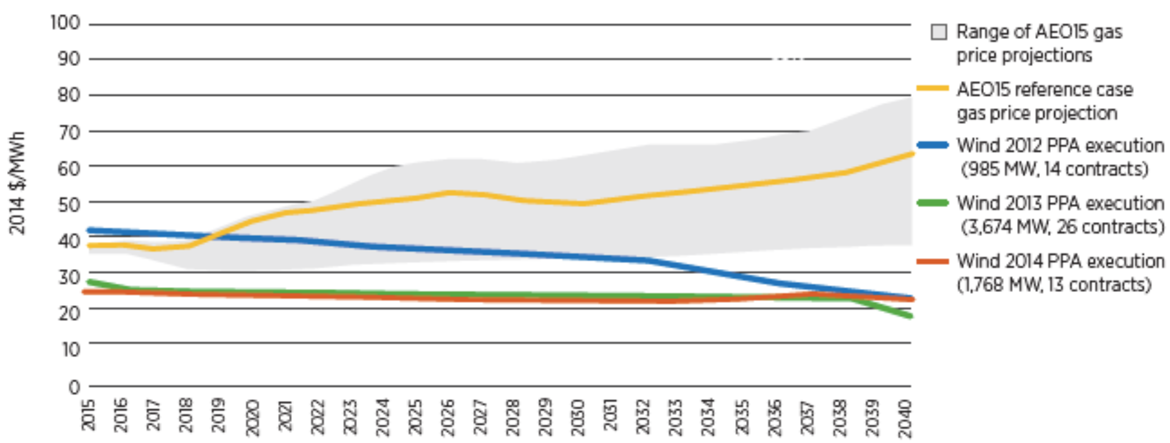
Wind energy resources today are among the very lowest cost sources of generation available to utilities. In recent years wind powered generation has been a dominant source of capacity additions across the US and are now playing an increasingly important role in diversifying the portfolios of electric utilities across the Southeast. Wind developments accounted for 33% of all new capacity additions in the US from 2007-2014, on par with natural gas and exceeding all other forms of energy.[16] New Orleans, too, has the opportunity to benefit significantly from low cost wind resources, particularly while strong federal financial incentives are still in place. To maximize benefits for customers, it is essential that the full range of options for accessing this resource be explored and contemporary real data on wind prices be recognized. The Council has articulated, and consistently reaffirmed, a vision for meeting more of our energy needs through renewable energy. This section will show why there has never before been a better time for the Council to act upon its clean energy vision.

Low Prices Drive Soaring Utility Adoption of Wind Energy

Utility interest in wind energy is being driven by historic low prices that are meeting and exceeding average prices for wholesale energy. Extensive empirical evidence is publicly available on wind energy prices, which is analyzed and reported each year by the Lawrence Berkeley National Laboratory (LBNL) in their annual Wind Technologies Market Report.

Last August, LBNL reported that 2014 had seen new record lows for wind prices, with average PPAs in the most productive interior region of the country in the mid-$20s / MWh range.[17] Even when factoring in transmission costs, these prices are highly competitive with wholesale electric costs across the country, making interior region wind a preferred option for utilities in the Southeast.

Figure 6.4: Average Long-Term Wind PPA Prices vs. Natural Gas Fuel Cost Projections[18]



Average Long-Term Wind PPA Prices vs. Natural Gas Fuel Cost Projections

The federal Production Tax Credit (PTC) has played a significant role in driving economies of scale that will keep wind cost competitive even after the incentive expires. It's renewal in December 2015, extended the current incentive of $23 / MWh for projects completed by the end of 2016,[2] after which the incentive steps down by 20% per year until its full expiration after 2019.

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[2] LBNL notes that cost savings from the PTC are likely about $15 / MWh

Installed costs for wind, which are not directly affected by the PTC, have also fallen considerably with nationwide capacity-weighted averages reaching $1,710 / kW in 2014 and costs in the interior region reaching $1,638 / kW.[3] Overall, wind prices have declined between 20% - 40% since late 2008. Meanwhile, improved turbine technology has increased capacity factors and seen more favorable terms for turbine purchasers through reduced turbine delivery lead time, extended O&M contract durations, improved warranty terms, and more stringent performance guarantees.[19]

The Department of Energy projects wind prices will continue to decline, while capacity factors are expected to improve. As part of the DOE's *Wind Vision* report, NREL conducted an extensive literature review on projected installation cost and capacity factor trends. Their "Mid-Cost" estimates for installed capital cost showed declines compared to 2014 of 1.1%-4.3% by 2020 and 1.9%-7.5% by 2030, wherein the lower end of the range corresponds with geographic areas of lower quality wind resources and the higher end of the range applies to geographic areas with higher quality wind resources. These prices are not affected by the existence or expiration of the PTC. Meanwhile capacity factors are estimated to improve between 4.3%-9.4% by 2020 and 10.6%-15.8% by 2030. The report's "High-Cost" estimate shows no reduction in cost over time, while the "Low-Cost" estimate would see a 37% reduction in LCOE by 2050.[20]

Proper Evaluation of Wind Considers Varied Options

When proper assumptions are utilized, wind resources are performing well in Integrated Resource Planning proceedings in other jurisdictions. Previous filings in this docket by the Alliance and Gulf States Renewable Energy Industries Association have identified the substantial adoption of wind energy recommended by SWEPCOin their IRP, while highlighting some of the differences in assumptions that largely explain why ENO's modeling inputs and results are inconsistent with contemporary industry practice.

Examples from beyond Louisiana borders illustrate the competitive cost of wind technology. For example, TVA called for 500-1,750 MW of wind energy resources even using outdated price and capacity factor assumptions in their Final 2015 IRP. Significantly, they evaluated numerous sources of wind resources including from within their service territory, through the Southwest

[3] These are all-in costs that take into account fixed-rate charges and financing interest rates.

Power Pool, through the Mid-Continent Independent System Operator, as well as wind energy imports from two proposed High Voltage Direct Current transmission projects.[21]

In Georgia, the Georgia Power Company issued a Request for Information in advance of its current IRP process. The request resulted in responses from 14 different companies regarding 40 different projects in 21 different locations including the Interior region, the Great Lakes region, and the Southern region. Of these, 30 projects were recognized as having positive net benefits, and a majority of those were recognized as having "significant benefits," particularly when attention was given to the various delivery methods available.[22] Georgia Power Company's experience shows that effective modeling of wind energy in IRP proceedings depends upon evaluation of a wide array of generation and transmission options. To do otherwise dramatically undervalues the beneficial financial opportunity for customers.

Stakeholders[4] in the 2015 Entergy Arkansas Inc. (EAI) IRP proceeding observed various assumptions for renewable energy being used by the utility that were out of date or otherwise inconsistent with empirical industry data. On August 14th, 2015 the stakeholders provided revised assumptions for wind and solar energy resources. By September 3rd, 2015 the EAI had incorporated the revised assumptions into Aurora for analysis and provided results back to the stakeholders on September 3rd, 2015. The results were then added to their IRP filing to the Arkansas Public Service Commission on October 30th, 2015.

The stakeholders recommendations for wind are in table 6.1 below:

[4] **Including SWEA, AEE, Audobon, and others.**

Table 6.1: Stakeholder Recommendations for EIA Wind Forecasting

	SPP Wind Imports	HVDC Wind	Local Wind
LCOE 2014$/MWh w/PTC (busbar)	$23.43	$23.43	$58
w/o PTC (adds $15/MWh)	$38.43	$38.43	$73
Transmission ($/MWh)	$15-$19	$15-$19	$0
Delivered Cost w/o PTC	$53.43-$57.43	$53.43-$57.43	$73
Installed Cost 2014$/kW (all-in)	$1,638	$1,638	$1,877
in 2020	$1,568	$1,568	$1,856
in 2030	$1,515	$1,515	$1,840
2014 Capacity Factor	51%	51%	38%
in 2020	54%	54%	41%
in 2030	57%	57%	44%
Capacity Value	15%	28%	15%

SPP/HVDC wind energy resource LCOE and Installed costs for 2014 are based on Lawrence Berkeley National Laboratory's *2014 Wind Technologies Market Report*[ii]. The PTC cost savings of $15/MWh is also reported by LBNL. All costs (excluding the PTC) and learning curves for Local wind energy resources are based off the Department of Energy's *Wind Vision* report Table H–3 and Table H–4 for Land4/TRG4 resources.[iii] All net capacity factors and learning curves are based off DOE's Table H-4 for TRG1 and TRG4 resources. HVDC's wind energy resource capacity values are based on analysis performed for the Tennessee Valley Authority.[iv]

The basis for these figures were drawn from the Department of Energy, NREL, and LBNL reports that have also been cited in this filing. It was additionally noted that the recommended assumptions were generally consistent with those used by SWEPCO in its IRP modeling, and further benefits were derived from modeling wind at more than one price point to better anticipate the effect of evolving market conditions. EAI modeled wind prices at $54 / MWh and at $47 / MWh. At $54 / MWh significant wind resources were selected in most scenarios up to 1,200 MW. When modeled at $47/ MW, the amount of wind selected doubled to 2,400 MW, reaffirming the value of evaluating multiple price points to better understand the value of potential wind resource acquisitions as prices continue to decline.[23]

One more example from Arkansas provides additional insight into price points for wind energy procured from the Interior region. Arkansas Electric Cooperative Corporation (AECC) entered into a wind PPA from south-central Oklahoma reported to have a nameplate capacity of 150 MW at a total cost of $250 million, or an installed project cost of roughly $1,667 / kW[24].

This validates the national figures and illustrates what is happening in the region for utilities accessing generation from SPP but located in a state served by MISO. According to MISO materials from June 2016,[25] the flowgate between MISO North/Central and MISO South has an available 1,000 MW of transfer capacity, offering clear access for ENO to cost-effective wind.

Following the Entergy Louisiana IRP proceeding, which suffered from many of the same deficiencies identified in ENO's IRP proceeding, SWEA conducted its own transmission analysis (included as Appendix 4) for delivering wind resources and came to the following key conclusions:

1. Cherry picking high cost examples. ELL identified three wind farms as representative of resources available from SPP but all 3 are located in high congestion areas. This did not represent a fair analysis of LMP differentials. The LMP differential for these three site are 119% higher than the other 12 sites SWEA evaluated.
2. Manufacturing costs. ELL modeled the highest cost delivery, point to point contracts, which would in practice represent exceedingly poor judgement on how to set up a PPA contract. The least-cost option is delivery through the SPP-EES (Entergy) Interface, the cost declines to almost nothing and could potentially be a source of revenue.

Figure 6.5: Wind Farms Evaluated for LMP Differential Values, 5-minute Increment

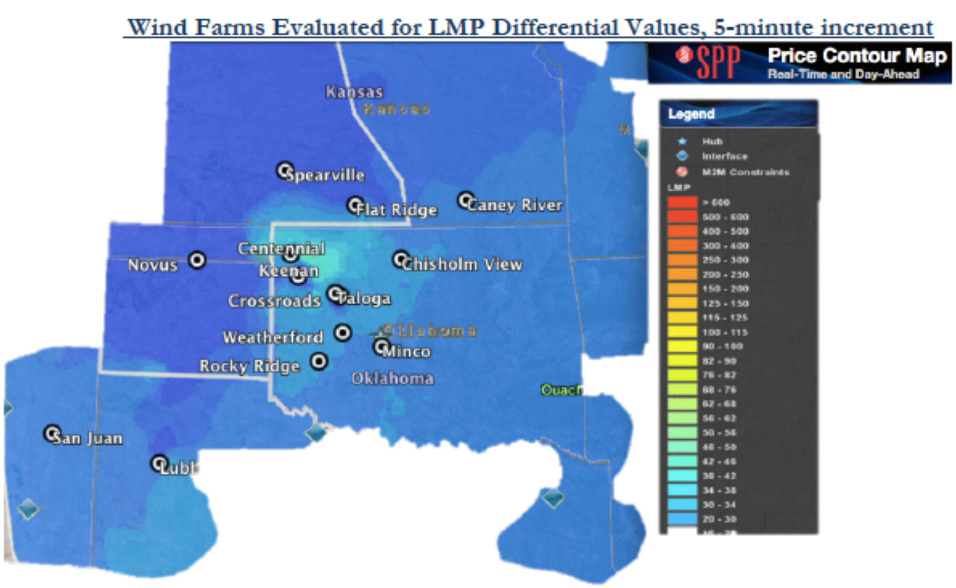


Table 6.2: Various LMP Differentials Based on Wind Farm Site and Energy Delivery Point

	Various LMP Differentials Based on Wind Farm Site and Energy Delivery Point ($/MWh)			
	EES.EGILD	EES.ELILD	Avg. ESS	SPP-EES INTERFACE
Spearville	$13.16	$11.93	$12.55	$4.51
Centennial	$17.21	$15.98	$16.59	$8.56
Kennan	$15.45	$14.22	$14.84	$6.80
Caney River	$8.32	$7.09	$7.71	-$0.33
Weatherford	$5.56	$4.34	$4.95	-$3.08
Chisholm View	$7.32	$6.10	$6.71	-$1.33
Minco	$6.02	$4.79	$5.40	-$2.63
Taloga	$4.64	$3.41	$4.03	-$4.01
Crossroads	$11.91	$10.69	$11.30	$3.26
Novus	$13.17	$11.95	$12.56	$4.52
San Juan	$3.47	$2.24	$2.85	-$5.18
Lubbock	$4.97	$3.74	$4.36	-$3.68
Rocky Ridge	$6.51	$5.29	$5.90	-$2.13
Flatridge	$8.26	$7.03	$7.64	-$0.39
Averages	$9.00	$7.77	$8.38	$0.35

Free Fuel Resource: Biogas

Biogas is simply gas that comes from biological processes like decomposition. Every city in the world creates biogas from the treatment of sewage. As human waste breaks down in large tanks, tons of methane and carbon dioxide are released.[26] This is called anaerobic digestion (AD) of sewage sludge by wastewater treatment plants (WWTP). As noted in Chapter 5, methane and carbon dioxide are dangerous greenhouse gases. By capturing this fuel and using it for energy, pollution and the WWTP electric bill are reduced. A 1 MW biogas CHP system in the U.S. reduces about 3,320 tons CO2e per year.[27]

New Orleans has two sewage treatment plants; one on each side of the Mississippi River. The East Bank plant can process up to 122 mgd (dry weather) per day. In 2013, the plant received about 98 mgd of flow. The West Bank plant has a treatment capacity of 20 mdg (dry weather) and processed about 10 mgd in 2013.[28]

Supply Alternatives: Capacity Resources, Purchased Power Agreements, Combined Heat and Power, Battery Storage and Microgrids

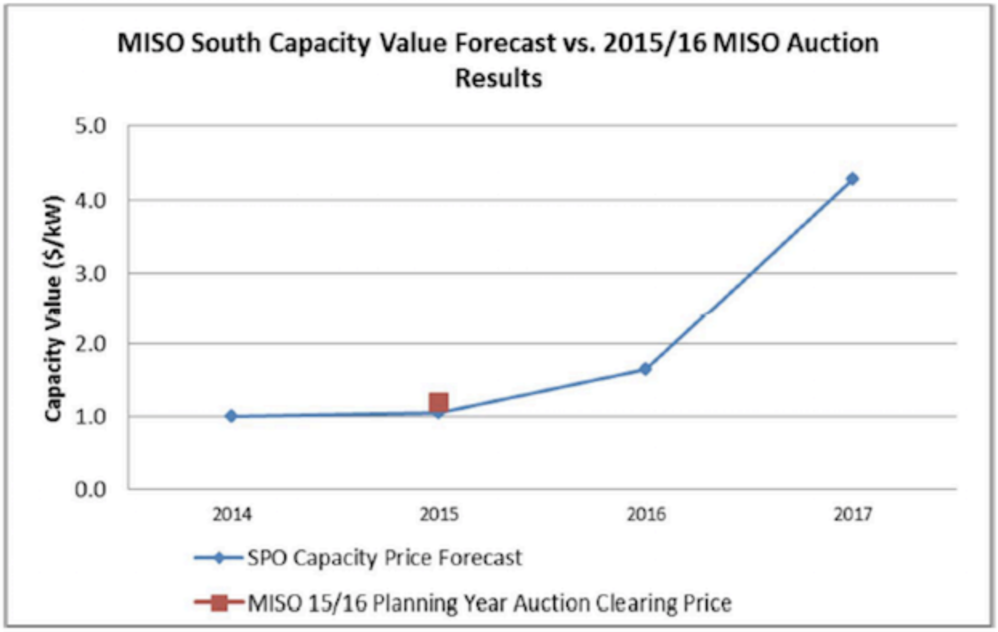
MISO Market Access to Capacity Resources

There are two types of resources that utilities are required to have. The first is energy, measured in Watts per hour, and the other is capacity, measured in total Watts. ENO has enough energy to meet its customer base needs, but the company asserts it is short on capacity.

MISO, Entergy System's Independent System Operator offers the opportunity to purchase capacity through Planning Resource Auctions (PRA). Purchases can be made from independent power producers or other power-generating Load Serving Entities (LSE) with available capacity. Auctions are held annually for each of the 10 load zones within the MISO footprint. The PRA auction takes place in March and addresses needs for the immediately following year. Notably, where PJM and other ISOs establish demand forecasts themselves, MISO LSEs project their own demand in the PRA and MISO (or a state if it so decides) establishes Reserve Margins.

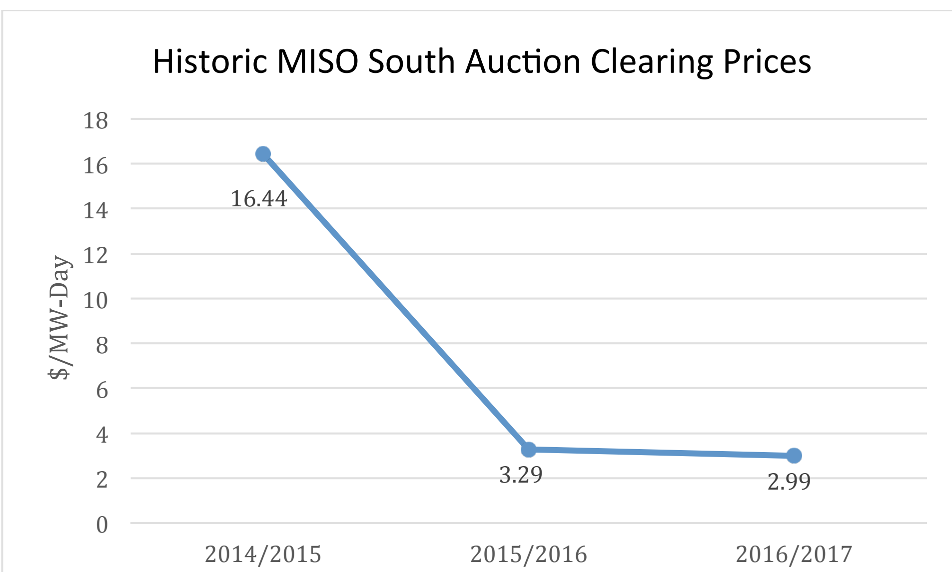
Contrary to ENO's projected MISO capacity costs in the first figure below (shown in $/kW-year), evidence from the MISO's Annual PRA show, in the second figure (shown in $/MW-day), a reduction of capacity costs in the years since Entergy joined the system. Because of excess capacity in the Southern MISO zones, the cost for a MW-Day in Zone 9 (Louisiana) at the April 2016 auction was $2.99. This is a price decrease of 10% from the prior year as the Zone 9 auction price was $ 3.29 per MW-Day in 2015. Prices in other MISO zones cleared a high of $72.00 / MW-Day and auction prices in the 100s of dollars in other adjacent systems.

Figure 6.6: MISO South Capacity Value Forecast v. 2015/16 MISO Auction Results



Source: 2015 ENO Integrated Resource Plan

Figure 6.7: Historic MISO South Auction Clearing Prices



Source: Data MISO Resource Planning Auction

The figures above from the most recent cost projections illustrate that there are clearly affordable capacity credits for purchase within MISO's Zone 9 through 2022.

MISO Credited Resources

Traditional fuel burning generating capacity is not the only opportunity to achieve credit for MISO Resource Planning requirements. MISO allows various resources in its Resource Planning Auction including demand response, energy efficiency, traditional generation, and behind the meter generation. Demand side initiatives are valuable in the MISO system, and the full MISO resource profile includes 12,000 MW of various kinds of demand side resources, including Load Modifying Resources, Emergency DR, and Demand Response Resources, each classified differently. ENO has an opportunity to not only cost-effectively reduce load, but to share benefits with customers by reducing emissions, reducing New Orleans' need for expensive peaking capacity, and selling DSM into the market when there is excess, all while complying with MISO Resource Planning Requirements. Without question, deploying demand resources is a less expensive and more beneficial alternative to address peaking needs than with expensive and inefficient fossil fuel-burning peaking generation like combustion turbines. More should be done to evaluate the potential financial benefits from credits in MISO for these resources, particularly in light of the Council's decision to implement DSM targets to meet a significant portion of projected load growth.

Purchased Power Agreements

Participation in the MISO marketplace gives New Orleans access to Purchased Power Agreements (PPAs) from across a large geographic area that can offer cost-effective reliable resources for Entergy New Orleans without requiring new generation construction and expensive O&M costs. PPAs are an important option for locking in cost-effective long-term (and even relatively short term) resources as needed for the utility. With the exception of contracts acquired with the Algiers Transfer, entered into by Entergy Louisiana, Entergy New Orleans has only entered into PPAs contract with other Entergy companies. Considering the scale of potentially cost effective PPA resources that could be available to New Orleans, this subject deserves additional attention by all parties before proceeding to decisions on selection of specific new build generation resources.

Current and Potential PPA Resources

Entergy New Orleans currently has 11 MW of Purchased Power Agreement (PPA) capacity, as a result of the Algiers Transfer from Entergy Louisiana. Of the 11 MW, 9 MW is from Occidental Chemical's Taft generating plant, located in St. Charles Parish. Occidental's CCGT plant was put into service in 2002 and Entergy Louisiana (ELL) currently has a PPA with the company for 480 MW, 125 MW of which is considered CCGT capacity, (useful for load-following) and 60 MW of which is considered peaking capacity.[29]

ELL's PPA with Occidental ends in 2018, and with it goes ENO's 9 MW of capacity[30]. Currently, this 480 MW of capacity remains uncontracted beyond 2018. This presents an opportunity for Entergy New Orleans to secure a PPA with Occidental Chemical for capacity that could meet City needs in the short term as demand side management, renewables, storage, and other resources are procured and brought on line. Moreover, the Oxy-Taft plant is located in the Down Stream of Gypsy (DSG) load pocket, is fewer than 20 miles away, and already linked to Orleans parish through two transmission lines, one through Little Gypsy and another through Ninemile. Additionally, upgrades to transmission within the DSG pocket are currently being considered through MISO's MTEP process which would further enhance the already sufficient access to this resource.[31]

Combined Heat and Power: Industrial Potential

Occidental's generation is not the only capacity available through a PPA. Louisiana's significant industrial system has enormous untapped capacity for electric generation through industrial cogeneration. A 2014 report prepared for Louisiana's Department of Natural Resources[32] estimated a total 1,480 MW of industrial combined heat and power (CHP)-based electricity generation (in the 2014 capacity market) , approximately 560 MW of which is considered cost-effective. Accessing capacity from CHP instalations through PPAs is made possible through MISO's integration across Louisiana.. Further, chemical and refining industries, located in the DSG make the use of industrial CHP an efficient way to put waste heat from these industries to use. Capturing this valuable energy would also mean continued downward pressure of capacity costs in the MISO market. Purchased Power Agreements can offer cost-effective reliable capacity for Entergy New Orleans without requiring new generation construction or expensive O&M costs, while locking in long-term (and potentially short term) resources as needed to meet local reliability requirements.

CHP for Resilience

Cities all over the country are meeting the challenge of resilience, and have adopted Combined Heat and Power (CHP) or co-gen as a tool for responsive, cost effective, resilient energy generation. Currently, the Alliance has identified only two CHP installations in Orleans Parish: a 5 MW combustion turbine plant owned by and sited at Tulane University, and 8 MW at New Orleans' University Medical Center (UMC). Entergy Thermal LLC,[33] (an unregulated subsidiary of Entergy Corporation) owns and manages this district energy project, offering cooling and heating to buildings at both the UMC campus, medical buildings, and a hotel in the nearby Central Business District.

CHP offers distributed generation that can meet energy needs even in emergency situations when electric transmission or distribution goes down. New York and other Northeastern cities saw enormous benefit from existing installed CHP during superstorm Sandy in 2012, with hospitals, universities, and multi-family buildings able to shelter in place with available emergency power[34]. In the three years following the storm, New York City, also a transmission island, installed 55 CHP projects across its five boroughs.

Installations of CHP throughout the New Orleans' infrastructure centers and neighborhoods could offer New Orleans efficient cooling centers, community resilience, and emergency staging locations during major storms. CHP systems offer greater resilience than emergency backup generators that run only in crisis because regularly utilized and maintained generation is more likely to be prepared in emergencies. Distributed CHP also allows quick installation times, averaging 3 months.[35] Working in tandem with New Orleans resilience efforts and including microgrids as part of a whole city strategy along with CHP could offer an effective answer to concerns of "islanding."

Adding CHP to hospitals is of particular benefit. According to national statistics, Healthcare organizations spend approximately $6.5B each year on electric bills.[36] Every $1 a non-profit healthcare organization saves on energy is equivalent to generating $20 in new revenues for hospitals.[37] CHP systems keep life-saving energy on in hospitals' during natural disasters. As of 2014, there were more than 200 hospitals with CHP in the U.S. systems.[38]

Year-Round Benefits from CHP

CHP offers enormous benefits in everyday operation, not just emergencies. The purpose of such installations is to meet demand where it is needed year round, thereby reducing transmission and distribution losses, and, perhaps more importantly, using energy effectively by capturing waste heat from generation and using the thermal energy for building uses like hot and cold water and HVAC purposes. Large buildings can dramatically reduce their energy needs (and demand) every day of the year by using energy generation that is cited nearby on onsite. By combining electric and thermal energy generation, CHP generally exceeds 70% efficiency (and can operate at over 80% efficiency), as opposed to electricity generation cited elsewhere which may reach 34% efficiency,[39] and then must be used to generate cooling or heating.

Efficiency and resilience are far from the only benefits offered by CHP. Emissions reductions are an enormous societal and health benefit, as DOE estimates that a 10 MW natural gas CHP system would offer an emissions savings of around 42,751 tons of CO2 a year. Distributed CHP offers reduced emissions, as efficiency can be double that of centralized generation. Savings from captured waste heat and transmission or distribution line losses, mean every mbtu of fuel generates less than half the criteria pollutants and carbon dioxide as a centralized peaking power plant.[40]

Moreover, levelized costs of energy (LCOE) are affordable for many CHP installations, as greater efficiency squeezes twice as much energy from the same fuel. A natural gas reciprocating engine, a mature technology that can be used for load shapes from baseload to peaking can offer an LCOE of about $0.06 per kWh.[41] Additionally, the rapid ramp-up of CHP could provide is a natural fit for support for continued growth of renewable energy in the city. Because CHP can ramp-up quickly, New Orleans' distribution system can be more easily balanced to respond to by providing a quick response to intermittency issues that may occur.

Technologies that provide CHP include reciprocating engines, gas or steam turbines, microturbines, and fuel cells. These various options should each be weighed against the site needs, and installations are most efficient when sized according to a building's thermal load.[42]

Battery Storage and Microgrids

New Orleans is currently ranked as a top 10 city for per capita rooftop solar penetration, with 37 MW installed in the parish. Battery back-up and planning with microgrids and resilience districts are part of a developing solution for dealing with emergency outages. The City of New Orleans is working with Sandia National Laboratories and the U.S. Department of Energy to develop resilience planning to ensure safety and resilience[43]. Resilience planning must be a citywide collaboration in order to create and implement the best grid.

Until very recently the discussions of battery storage have been easily dismissed as "too expensive," and still just the "holy grail" of energy, suggesting the technology is not mature enough to model, or plan for, or even consider. While the Alliance is not prepared to include battery storage in our portfolios at this time, it would be inappropriate to move forward with either a 20 year planning process or the decision to side-step storage potential by selecting a more traditional peaking resource without thoughtful consideration of the state of the market and the value of battery storage.

Multiple Values of Energy Storage

Storage is a useful resource that offers multiple services including load balancing, grid-optimization, improved dispatch-ability of intermittent resources, peaking capacity, transmission islanding concerns, and further support for the growth of distributed energy, including free fuel generation.

Large IOUs, such as Southern California Edison (SCE), are already procuring energy storage to meet local capacity requirements. In fact, SCE procured 235 MW of battery energy storage in 2014 on the basis of cost effectiveness to meet local capacity needs (California's procurement target only required 50 MW of energy storage by 2018). SCE determined through competitive solicitation that energy storage provided capacity more cost-effectively than alternatives, including gas-fired generation, to meet the specifications of its 2013 RFP. [44]

Small utilities, such as municipals and Co-ops, are selecting energy storage in order to serve their needs and reach clean energy goals as small-scale utility storage has the ability to utilize renewable energy reliably. For example, Connecticut Municipal Energy Electrical Cooperative (CMEEC) recently announce the procurement of 13 MW of solar and 6 MW hours of energy storage to provide cost effective, clean, and dispatch able solar capacity to their customers. [45]

Methods of Valuation

Because energy storage offers a wide variety of services and values, it is important to consider valuation methodologies,which fairly weigh the costs and benefits. Storage offers not just energy, but flexibility, energy security, and standby. Perhaps an apt metric to use in evaluating end-costs should be Capacity Value, which is the metric used for MISO's Planning Resource Auction forward-year capacity market. Assessing capacity options sold by the kW-year or MW-day as in capacity auctions may offer a better comparison. Additionally, storage offers operational benefits that traditional generating capacity does not, like low fuel costs when paired with clean, abundant, and inexpensive off-peak wind or solar. Operational benefits that storage offers, such as reduced fuel costs, startup costs, and (when distributed) reduced losses, should be recognized and credited for their value to customers and the market.

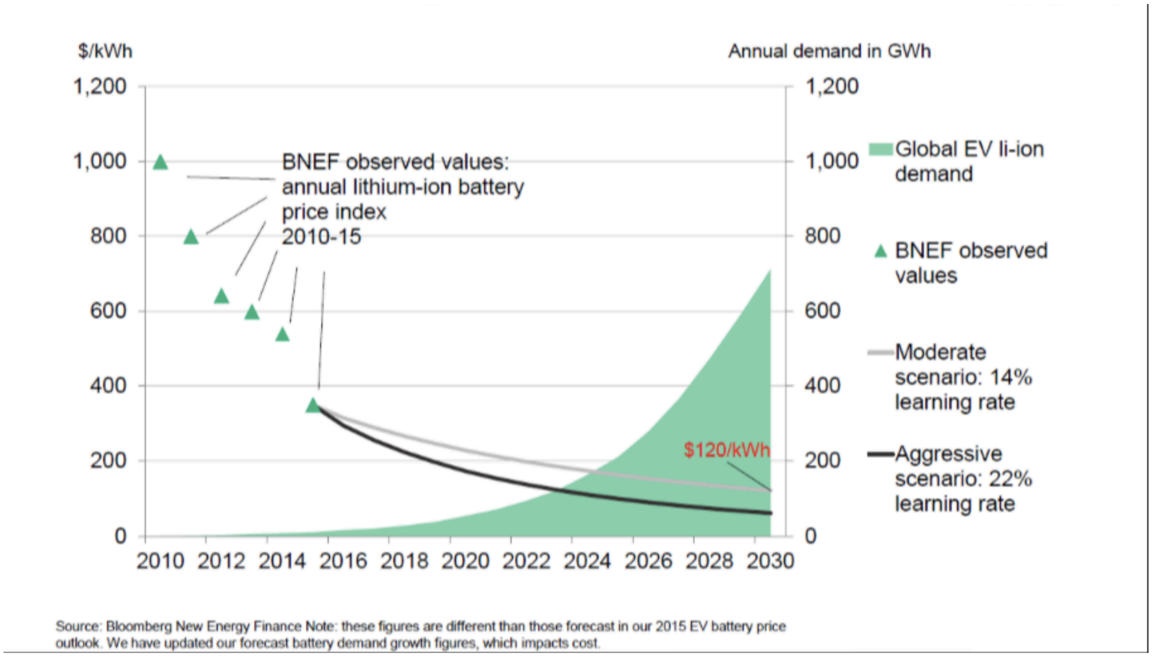
Additionally, energy storage may offer a chance to purchase interior wind at night through the MISO system when energy costs are near $0.01 per kwh, to be used during peaking hours when market costs can be 20-30 times as expensive. As installed costs continue to decline rapidly, this particular use of storage may prove to be one of the more cost-effective ways to manage peak load.

Most importantly, energy storage systems have the ability to provide many or all of these stacked services and benefits in a single or fleet (if distributed) application. In a study commissioned by Texas distribution utility Oncor, The Brattle Group found that over 5 GW of cost effective storage could be deployed ERCOT-wide by 2020 measuring the benefits of storage systems providing stacked values.[46]

Battery Storage Market Forecast

As previously asserted, battery storage has long been considered a "someday" solution to major problems with renewables, as one of their purposes is to smooth out the intermittency of resources like wind and solar. However, the utility industry is now observing dramatic shifts in economics associated with the technology similar to the precipitous drop in prices for wind and solar in recent years, and the "someday" perception is quickly shifting to cost-effective procurements across the country. In November 2015, IHS[47] reported a 52% install cost decline in battery storage from 2012 to 2015, and expects yet another 50% cost decline by 2019 In the US. Lazard's report on the Levelized Cost of Storage (Fall 2015) likewise projects 47% Lithium-ion price declines by 2019.[48] Bloomberg New Energy Finance research forecasts released in June, 2016[49] suggests lithium-ion battery prices will fall quickly in the coming years.

Figure 6.8 $/kWh trend for Lithium-Ion Battery 2010-2030.



These cost declines will drive an enormous adoption of storage in the coming years. Another IHS Market report, released July 28, 2016 forecasts global grid-connected energy storage market will double in 2016, from 1.4 GWh in 2015 to 2.9GWh this year. IHS's report goes on to show that number rise to 21 GWh in the next 9 years, with Lithium-ion batteries leading the charge. "Energy storage is set to grow as fast as solar photovoltaic energy has in recent years."[50] This analysis illustrates a widely held understanding by the global energy industry that storage markets are maturing quickly and planning for adoption is appropriate.

In short, the consensus on forecasting of cost reductions and value increases for energy storage is worth highlighting. This IRP/IResP cycle coincides with real decisions on how New Orleans will be a more resilient city, and how our energy system will serve customers reliably, affordably, and sustainably for the next 30 years. The Alliance acknowledges ENO's 2015 IRP's pricing forecasts include data from 2013-2014, and the length of this proceeding may have made maturing technologies difficult to model within their IRP. However, if storage technologies are not fully considered, with up-to date cost data and full consideration of the myriad grid benefits energy storage systems can offer over traditional grid assets before large investment decisions are made, ENO's portfolio will sit firmly in the 20th century for another 30 years. Alternatively, due-diligence, full vetting, and consideration of the of resource options available over the 20 year time horizon, even as alternatives improve year over year, will only make New Orleans and Entergy stronger.

Conclusion

There has never been a better time to fulfill the Council's vision for clean energy than now with utility scale renewable energy and storage. Price points have fallen sharply to historic lows that now effectively compete with natural gas, and utilities across the region and the country are aggressively installing major new renewable energy capacity additions and entering into PPA contracts. Additionally, the MISO resource planning auction continues to offer cost-effective capacity for at least 5-6 years, and potentially longer, depending on market realities. PPAs from industrial generators and independent power producers, along with distributed CHP are valuable and viable resources that should be included in resource planning, especially when customer costs are reduced and external benefits, such as additional city resilience, are realized. Council guidance is needed to ensure New Orleans benefits.

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CHAPTER 7

ASSUMPTIONS AND PORTFOLIO DEVELOPMENT

Overview

This section is designed to walk the reader through the Alliance's thinking on the Integrated Resilience Plan's three portfolios. First, we discuss the Sensitivity analysis. Second, generating unit retirement assumptions, and costs. Next we offer up-to-date Levelized Costs of Energy for the resources offered in the portfolios. The Alliance recognizes that LCOE is a good metric for energy but not ideal for comparing resources that bring other services to the grid like flexibility and standby availability. For these types of resources we will provide a Capacity Value (kW-yr).

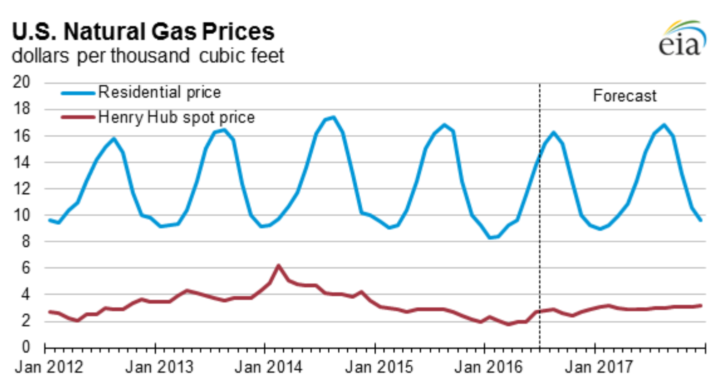
Sensitivities

Prudent planning requires multiple realistic forecast scenarios for a range of sensitivities including natural gas price forecasts, wholesale market price forecast, emissions pricing, and various load growth assumptions, along with others not included here. Policy drivers including federal regulations and city resolutions make multiple resources plans even more valuable. The multiple resource plans should include transparent customer costs to allow the Council to make the best-informed decisions.

Load Growth Variability

Although the Alliance is justified in questioning ENO's load projections as shown in Chapter 3, for the purposes of portfolio development in this filing, the Alliance uses 1,451 MW as the total resource need. Chapter 3 also described various inputs for load projections that include realities like increasing deployment demand response, reduced energy waste, and increased distributed generation. Other variables that may influence peak load include weather, both discrete events and changing climate trends, changes in economic realities, and industrial growth. This resource plan offers analysis based on current and historic, local and national, trends.

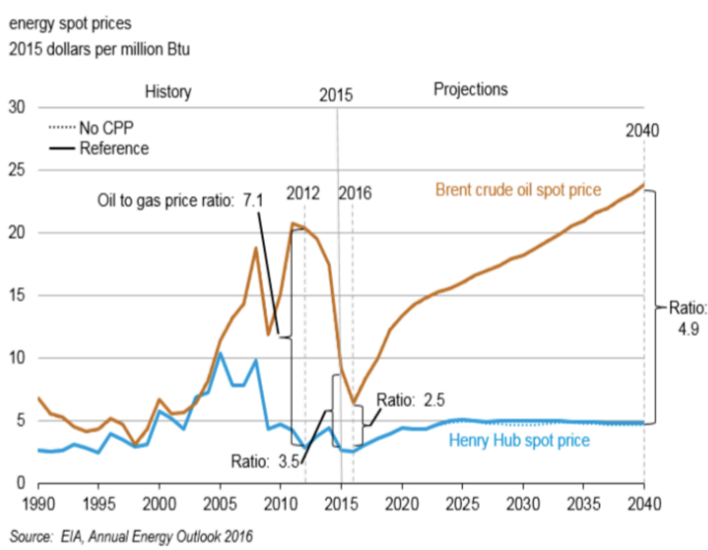
Figure 7.1: U.S. Natural Gas Prices in Dollars Per Thousand Cubic Feet



Natural Gas Price Forecast

For purposes of levelized costs of natural gas fired resources, this resource plan uses recent history and NYMEX Henry Hub forward short term prices. Natural gas prices are historically volatile for a variety of reasons, including high demand or surplus, regulation, industrial sales, exports, and weather. Currently, natural gas prices are at historic lows, there exists a surplus of stocks, and coal generation is retiring across the country. As a result of these pressures, there is uncertainty in long-term forecasts. Short-term forecasts do show increases over the next 4 years. Strong growth in global LNG sales and impacts from Clean Power Plan regulations are expected to put upward pressure on natural gas market prices until 2020 when EIA assumes they will hold steady, based on continued growth in extraction.

Figure 7.2 – 2015 Energy Spot Prices



Without a doubt, using less fuel is more economical for customers. If demand for natural gas stays relatively steady, then fuel costs should remain stable for years to come. Using less fuel is easy with today's technology. Either capturing wasted energy with energy efficiency programs or using generating resources with no fuel requirements, using less fuel reduces risk to customers.

Wholesale Market Price Forecast

As noted in previous chapters, MISO's System planning continues to show available surplus capacity until 2022, and recent historic loads show slow to no growth. While the North/Central Region's capacity market will continue to tighten as a result of coal generation retirements,[1] it appears that already abundant natural gas generation and industrial co-generation will keep cost-effective capacity and energy available for the next 5-6 years. The addition of demand response in the Entergy System as new programs are deployed and Advanced Metering Infrastructure is installed across the Entergy footprint will keep wholesale market prices low.

Carbon

In previous iterations of ENO's IRP, the Alliance submitted comments supporting planning that acknowledges the likelihood of carbon regulation. ENO's February filing makes clear the utility's hesitation to include CO2 pricing in the reference case, despite other Entergy Corporation utilities' inclusion of carbon pricing in reference case sensitivities in other jurisdictions.[2] Indeed, Entergy Arkansas' 2015 IRP describes a range of potential carbon regulations and includes fair assumptions for both timeline and cost in its reference case, with carbon pricing beginning in 2019. ENO asserts that including carbon pricing in all scenarios is *imprudent*. The Alliance believes the opposite is true. It is clear that climate change is happening, that carbon emissions contribute to climate change and planning should include a price on carbon. The Alliance submits is irresponsible business planning to ignore this fact. ENO's refusal to show modeled carbon pricing within levelized costs of energy (LCOE) hides a very real risk to ratepayers.

The Clean Power Plan, while currently stayed at the federal level, is currently undergoing analysis and planning by the Louisiana Department of Environmental Quality at the direction of Governor Edwards. Forthcoming State Implementation Plans will likely create markets for carbon trading, and without appropriate modeling and risk analysis including this scenario, with transparent cost impacts to consumers, the Council is left without fair choices.

Portfolio Assumptions

All of the portfolios assume the following:

1. Entergy Louisiana's PPA for 9 MW with OxyTaft contract ends 2018
2. ELL's power agreements that transferred with Algiers can legally be retired early
3. ENO's 1 MW solar farm and back up battery deliver .5 MW of capacity
4. Exceeds ENO's load projections[i]

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[i] As discussed in Chapter 3 Load Projections, the Alliance asserts that New Orleans does not have a capacity problem. However, for the purposes of this filing, each of the portfolios were designed to exceed ENO's stated capacity requirements to show confidence that energy and capacity needs can be met, even if all resources in a given portfolio are not selected.

5. Residential rooftop solar has a base rate of growth of 7% based on ENO's projections

20% Clean Energy by 2020

This portfolio calculates 20% based on energy not capacity. It retires 102.2 MW of fossil fuel-fired generation in 2018 including ENO's coal power contract and Algier's CT, oil, and legacy gas plants.

Balanced PPA

This portfolio focuses on balancing existing, dispatchable co-generation resources in the Downstream Gypsy load pocket with low cost wind generation. The Algiers PPA with Occidental is retired in 2018 per the contract agreement but the other Algiers related resources are retired in 2020.

Distributed Generating

As various distributed energy resources become available and ever more cost-effective, this portfolio deploys rooftop and fixed tilt solar, CHP from area hospitals, and other major city infrastructure locations, as well as microgrids to better respond to storm islanding concerns. In this scenario, capacity resource acquisition is part of a coordinated effort with the city and private entities to build a more resilient New Orleans through robust distributed generation. This portfolio would be beneficial in a high fuel-cost future, as the distributed solar uses free fuel, and CHP realizes greater energy returns from every unit of fuel. Along with storm hardening for distribution and transmission to improve resilience to weather events, the distributed capacity offers greater confidence in New Orleans in the face of changing climate and rising sea levels.

In designing the three portfolios, the IResP made retirement choices for existing resources. Retirement dates are based generally on targets for clean energy deployment and minimizing exposure to global market forces. No information was provided by ENO regarding PPA contract terms or contractual obligations for each resource. Therefore, the Alliance assumes that early retirements are legally permissible.

Resource Retirements

The resource retirement dates were also not provided. It is clear that resources are retired over the planning period because the available capacity in ENO's IRP reduces over time. The following portfolio assumptions compared ENO's reported capacity availability with current portfolio resources and made adjustments accordingly. The most accelerated reductions in existing resources is the early retirement of all coal, CT, legacy gas, and oil resources after 2018, in the 20% Clean portfolio. The Alliance assumed that units whose fuel sources are known to cause substantial pollution would be retired earlier than other fuel types. The extrapolation likely includes assumption errors and is only meant to illustrate portfolio outcomes in Chapter 9: Plan Results.

The Balanced PPA portfolio retires Algiers' related resources early. The Distributed Generation portfolio approximates ENO's IRP Stakeholder Case reductions.

Table 7.1 – Existing ENO Resource Estimated Retirement Dates

Existing ENO Resources				**Planned Retirement Date (year)**		
MW	**Fuel**	**Unit**	**Load**	**Portfolio: 20 % Clean**	**Portfolio: Balanced PPA**	**Portfolio: DG**
510	CCGT	Union 1	LF			
392	Nuclear	WBL: Grand Gulf, Riverbend	Base			
112	CCGT	Ninemile 6	LF			
32	Coal	WBL	Base	2018	2020	2034
21	Nuclear	Waterford 3 (Algiers)	Base			
13	Legacy Gas	Ninemile 4 (Algiers)	LF	2018	2020	2028
13	Legacy Gas	Ninemale 5 (Algiers)	LF	2018	2020	2031
10	Legacy Gas	Little Gypsy 3 (Algiers)	LF	2018	2020	2027
9	CCGT	Oxy-Taft (Algiers)	All	2018	2018	2018
8	Legacy Gas	Little Gypsy 2 (Algiers)	LF	2018	2020	2029
8	Legacy Gas	Waterford 2 (Algiers)	LF	2018	2020	2028
7	CCGT	Acadia (Algiers)	LF		2020	2032
7	Legacy Gas	Waterford 1 (Algiers)	LF	2018	2020	2033
6	CCGT	Ninemile 6 (Algiers)	LF		2020	
4	Nuclear	Riverbend (Algiers)	Base		2020	
3	Nuclear	GG (Algiers)	Base		2020	
2	CCGT	Perryville 1 (Algiers)	LF		2020	

2	Hydro	Vidalia (Algiers)	Peaking		2020	
1	CT	Perryville 2 (Algiers)	Peaking	2018	2020	2027
1	Oil	Waterford 4 (Algiers)	Peaking	2018	2020	2020
1	CCGT	Sterlington 7 (Algiers)	Peaking		2020	2027
0.4	Hydro	Toledo Bend (Algiers)	Peaking			
0.2	Legacy Gas	Buras 8 (Algiers)	Peaking	2018	2020	2032

Resource Assumptions:

Energy Efficiency and Demand Response: All the portfolios incorporate the Council's energy efficiency targets. MW from energy efficiency and demand response show up as a resource instead of load reduction. For more information on the assumptions to calculate MW targets see Appendix 2.

Voltage Reduction: Uses Volt/Var Optimization with a high case of 2.5% savings and 1.5% savings in the low case.

Utility Scale Solar: Capacity discount rate of 25% according to MISO capacity credit.

Residential solar: Rooftop solar was included as a resource instead of load reduction. It follows the capacity discount rate of 25% assigned by MISO to solar power.

Wind: PPA has a capacity discount rate of 14.7% as cited by MISO.

Capacity market: it is assumed that ENO continues to be a member of MISO through the 20-year period and has access to the capacity markets.

Microgrids with CHP or solar: Each microgrid is a 5 MW system based on information based on Sandia Labs modeling work.

Hospital CHP: This resource places an 8 MW CHP unit in 5 area hospitals including New Orleans East Hospital, Tulane University Hosptial, Ochsner Baptist, Touro, and Children's. Eight MW is based on the installation at the University Medical Center.

Biogas CHP: The MW from biogas assumes 580 BTU/ft3 LHV and 41% generator electrical efficiency. The CHP system operating 8000 hours per year should produce 29 kW for each mgd treated in the sewage treatment plant. Based on the formula for biogas (1 MGD wastewater flow= 29 kW power)[3], the East Bank plant should produce 2,842 kW and the West Bank plant should produce 290 kW.[4]

Industrial Cogeneration: Occidental has a CCGT power plant located approximately 25 miles from New Orleans' City Hall. It is assumed that a PPA with this industrial customer would meet the needs of the City because ELL has described its PPA with OxyTaft as a resource providing base load, load following, and peaking resource.

Levelized Costs of Energy

This IResP considers Levelized Costs of Energy (LCOE), analyzed as $/kwh, as a priority in discussing cost factors of resources. LCOE, rather than installed capital costs, gives a more clear understanding of consumer impacts. Capital costs are clearly important in developing a whole picture of the portfolio, and are included in calculation of LCOE. The benefit of including sensitivities like costs of natural gas and other fuel costs, external costs like emissions, efficient use of fuel, market value, and capacity factors as part of the analysis offers a better picture of how resources will affect customers.

The chart below shows fair and current LCOE of resources included in the portfolio resources. The Alliance used well-respected sources for LCOE, including the 9th annual LCOE analysis by Lazard Global Power and Energy Infrastructure Group, a financial advisory and asset management firm that releases respected analysis of energy costs annually for use by the energy and infrastructure sector. The Department of Energy and Energy Information Agency's tool for LCOE calculation was used for further corroboration. Of note, LCOEs listed do not include Federal Investment Tax credit or Production Tax Credits, or added costs of carbon. Lazard numbers assume a natural gas price of $3.50 per MMBtu for all technologies, other than NG reciprocating engine, which assumes $5.50 per MMBtu. EIA numbers assume a natural gas price of $4.40 per MMBtu. Also, wind technology numbers are included from recent purchased power contracts. Finally, for resources not described by Lazard or EIA LCOE analysis, the Alliance has included LCOEs from studies conducted in the past 4 years, with sources end-noted.

Table 7.2 – Comparisons of Levelized Costs of Energy

Comparisons of Levelized Costs of Energy[5]				
Excluding Externalities (cost for carbon, health costs, environmental costs)				
Technology	LCOE per kWh (Lazard)	LCOE per kWh (OpenEI)		
Gas Peaking	$0.17 - $0.22	$ 0.14 - $0.34		
CCGT	$.05 - $.08	$0.05 - $0.08		
NG Reciprocating Engine CHP	$0.07 - $0.10			

Fuel Cell CHP	$0.11 - $0.17	$ 0.10 - $0.16		
Microturbine CHP	$0.08 - $0.09			
Solar (Crystalline, Utility Tracking)	$0.06 - $0.07	$0.06 - $0.32[6]		
Solar (UtilityThinFilm,Utility Tracking)	$0.05 - $0.06			
Solar (Community)	$0.08 - $0.14			
			SPP 2015[7]	HVCD[8]
Wind (onshore PPA)	$0.03 - $0.08	$0.04 - $0.08	$0.02	$0.02
Voltage Reduction[9]	$0.03	$0.03		
Demand Side Management[10]	$0.03	$0.03		
Co-gen PPA (OXY CCGT)	$.0.04 - $0.07[11]	$.0.04 - $0.07		

Conclusion

The assumptions included in this IResP aim to take into account various scenarios for current resource retirement, with the intention to show the feasibility of meeting capacity needs with cleaner energy alternatives. The Sensitivities described herein are important considerations for policy decision-making. Market drivers unanimously support adoption of clean, least-cost resources to respond to needs over the time horizon. Levelized costs of energy offer a clearer picture of customer impacts than do simple capital costs. Policy decisions and regulations that take external costs and levelized costs into account are prudent and appropriate when developing a resource plan that best fits New Orleans.

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2 Entergy Arkansas Integrated Resource Plan, 2015, pg 26.

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4 Black & Veatch. Sewage and Water Board of New Orleans. Report on Operations for 2013

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CHAPTER 8

RESULTS

Overview

The Integrated *Resilience* Plan projects future energy needs, offers cost evaluations, analyzes current and future technology, and gives more alternatives worthy of consideration. The Resilience Plan includes externalized costs of energy production like climate change and health impacts and prioritizes resources that offer grid integrity. The Alliance presents the Council with an array of future scenarios and portfolios that minimizes risk to human beings, allows the grid system time to adjust to an uncertain future, and keeps bills affordable.

The Portfolios

This IResP offers portfolios that represent truly different choices for the Council's consideration. Each of these portfolios responds to needs and scenarios the Council, Entergy New Orleans and other stakeholders have asserted are critical for the future of New Orleans. The following three portfolios include continued use of ENO's existing generating capacity plus varying amounts of free-fuel resources, energy efficiency, demand response, and purchased power agreements.

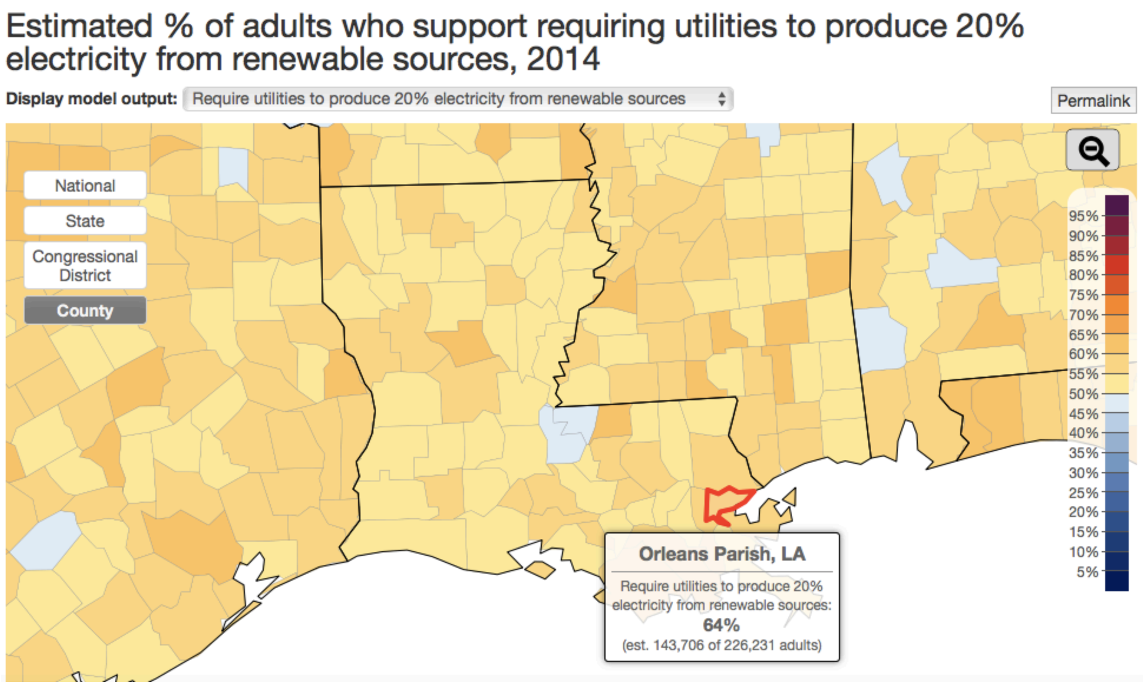
Goals for Each Portfolio:

- Meets peak energy needs
- Ensures reliability
- Maintains affordable bills
- Complies with Council energy efficiency targets
- Manages risk of fuel price spikes in the natural gas and coal markets
- Manages risk of carbon, NOx, SOx, MATS, and other costs connected to environmental regulation
- Decreases risk of storm damage to critical infrastructure
- Protects the city from additional sinking related to continued groundwater pumping
- Reduces externalized costs to New Orleans residents

20% Clean Energy by 2020:

This portfolio stems from a local movement to commit New Orleans to a clean energy goal of 20% by 2020. This goal has broad support in the New Orleans community, a conclusion reinforced by a study from the Yale Project on Climate Change Communication and the George Mason Center for Climate Change Communication. In this well-respected public opinion study, 64% of Orleans Parish residents support a 20% renewable energy goal.[1]

Figure 8.1



All of the renewable energy choices have LCOE that fall under the LCOE for a peaking CT resource. As noted in the assumptions, 102.2 MW are retired in 2018 leaving 1060.8 MW needed. To meet peak and capacity needs, this portfolio utilizes a short-term PPA contract with nearby Occidental co-generation plant for one year. This supports an accelerated timetable for renewable energy deployment. Market purchases are not necessary beyond 2018.

20% Clean Energy by 2020

Load & Capability 2015—2035	2015	2016	2017	2018	2019	2020	2021	2022	2023
Requirements									
Base, LF, & Peak Load		1,125	1,136	1,143	1,153	1,159	1,163	1,175	1,183
Reserve Margin (12%)		135	136	137	138	139	140	141	142
Total Requirements		1,260	1,273	1,280	1,291	1,298	1,303	1,316	1,325
Existing Resources									
Existing Resources		1162.6	1162.6	1060	1060	1060	1060	1060	1060
Solar +Battery		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total Existing		1163.1	1162.6	1060	1060	1060	1060	1060	1060
CAPACITY DEFICIT		97	110	220	231	238	243	256	265
LOAD SERVING DEFICIT		-38	-27	83	93	99	103	115	123
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Planned Resources for ENO Capital Additions									
Sewage & Water Board Biogas				3.1	3.1	3.1	3.1	3.1	3.1
Microgrids with Solar or CHP			5	10	15	20	25	25	25
Utility Scale Solar Power Plant (1)			25	25	25	25	25	50	50
Community Solar (2)			1.0	2.0	3.0	4.0	5.0	5.0	5.0
Residential Rooftop Solar (3)	6.9	7.4	7.9	8.4	9.0	9.6	10.2	10.8	11.4
DR		5.0	10.0	17.0	24.0	29.0	37.0	46.0	56.0
Energy Smart Energy Efficiency Programs (4)		8	13	20	29	41	54	67	81
Voltage Reduction (5)			28	29	29	29	29	29	30
TOTAL ENO CAPITAL INVESTMENT		20	90	111	134	158	185	233	258
PPA Wind power (6)				29.4	29.4	29.4	29.4	59.8	59.8
PPA Co-Generation Oxy			50	100	100	100	50		
TOTAL PPA		0	50	129	129	129	79	60	60
Capacity Market Purchase Option		77	-30	-20	-32	-49	-22	-37	-53

1. Utility scale solar capacity is discounted 25% based on MISO.
2. Community Solar capacity is discounted 25% based on MISO.
3. Rooftop solar capacity discount rate of 20% based on Lazard. Estimated growth is 7% based on ENO's estimate in the netmetering docket.
4. Based on EAI 0.31 ratio. Figures calculated from a 2014 base year rather than the previous year's gross sales.
5. Voltage reduction high case with 2.5% savings and VoltVar technology
6. PPA Wind Power is 200MW nameplate, 29.4 MW is capacity value assigned by MISO and another 100 MW is added in 2020.
6. 5 year PPA with Occidental Co-generation unit

*Note MW are cumulative

2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
1,193	1,201	1,209	1,220	1,230	1,241	1,251	1,261	1,271	1,281	1,291	1,301
143	144	145	146	148	149	150	151	153	154	155	156
1,336	1,345	1,355	1,366	1,378	1,390	1,401	1,412	1,424	1,435	1,446	1457
1060	1060	1060	1060	1060	1060	1060	1060	1060	1060	1060	1060
0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
1060	1060	1060	1060	1060	1060	1060	1060	1060	1060	1060	1060
276	285	295	306	318	330	341	352	364	375	386	397
133	141	149	160	170	181	191	201	211	221	231	241

2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
25	25	25	25	25	25	25	25	25	25	25	25
50	50	50	50	50	50	50	50	50	50	50	50
5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
12.0	12.6	13.2	13.8	14.4	15.0	15.6	16.2	16.8	17.4	18.0	18.6
68.0	76.0	78.0	84.0	90.0	99.0	104.0	108.0	106.0	111.0	116.0	121.0
94	108	128	142	155	165	178	191	209	219	229	238
30	30	30	31	31	31	31	32	32	32	32	33
284	307	329	350	370	390	409	427	444	459	475	490
59.8	59.8	59.8	59.8	59.8	59.8	59.8	59.8	59.8	59.8	59.8	59.8
60	60	60	60	60	60	60	60	60	60	60	60
-68	-81	-94	-104	-112	-120	-128	-135	-139	-144	-149	-153

Balanced PPA: This portfolio focuses on balancing existing, dispatchable co-generation resources in the Downstream Gypsy load pocket with lowest cost wind generation. The Algiers PPA with Occidental is retired in 2018 per the contract agreement and the other Algiers related resources are retired in 2020. The Coal power is also retired in 2020. PPA Wind Power for 200MW nameplate is added in 2017 (29.4 MW capacity value assigned by MISO) and another 100 MW is added in 2020. Voltage reduction is the low case with 1.5% savings and VoltVar technology. This option reveals that ratepayers do not have to invest in a brand new power plant because there is dispatchable power already available in the load pocket approximately 25 miles from City Hall. The wind power PPA allows the Council to boost its renewable energy resources. Market purchases are not necessary beyond 2017.

Load & Capability 2016—2035									
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
MW Requirements									
Base, LF, & Peak Load		1,125	1,136	1,143	1,153	1,159	1,163	1,175	1,183
Reserve Margin (12%)		135	136	137	138	139	140	141	142
Total MW Requirement		1,260	1,273	1,280	1,291	1,298	1,303	1,316	1,325
Existing Resources									
ENO and Algiers Resources		1162.6	1162.6	1153.6	1035	1035	1035	1035	1035
Solar +Battery		1	1	1	1	1	1	1	1
Total Existing		1163.6	1162.6	1153.6	1035	1035	1035	1035	1035
CAPACITY DEFICIT		96	110	126	256	263	268	281	290
LOAD SERVING DEFICIT		-39	-27	-11	118	124	128	140	148
New Resource Options									
Residential rooftop solar (1)	6.9	7.4	7.9	8.4	9.0	9.6	10.2	10.8	11.4
DR (2)		5.0	10.0	17.0	24.0	29.0	37.0	46.0	56.0
Energy Smart (2)		8	13	20	29	41	54	67	81
Voltage Reduction (3)					17	17	17	17	17
TOTAL NEW RESOURCES		20	31	45	79	97	118	141	165
PPA Wind power (4)			29.4	29.4	29.4	44.1	44.1	44.1	44.1
PPA Co-Generation Oxy (5)			100	150	150	150	150	150	100
TOTAL PPA	0	0	129	179	179	194	194	194	144
Capacity Market Purchase Option		76	-50	-98	-2	-28	-44	-54	-20

1. Rooftop solar capacity discount rate of 20% based on Lazard. Estimated growth is 7% based on ENO's estimate in the netmetering docket.
2. Energy Smart is based on EAI 0.31 ratio, these figures are calculated from a 2014 base year rather than the previous year's gross sales
3. Voltage reduction low case with 1.5% savings and VoltVar technology
4. PPA Wind Power is 200MW nameplate, 29.4 MW is capacity value assigned by MISO and another 100 MW is added in 2020.
5. 10 year PPA with Occidental Co-generation unit

*Note MW are cumulative

2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1,193	1,201	1,209	1,220	1,230	1,241	1,251	1,261	1,271	1,281	1,291	1,301
143	144	145	146	148	149	150	151	153	154	155	156
1,336	1,345	1,355	1,366	1,378	1,390	1,401	1,412	1,424	1,435	1,446	1457
1035	1035	1035	1035	1035	1035	1035	1035	1035	1035	1035	1035
1	1	1	1	1	1	1	1	1	1	1	1
1035	1035	1035	1035	1035	1035	1035	1035	1035	1035	1035	1035
301	310	320	331	343	355	366	377	389	400	411	422
158	166	174	185	195	206	216	226	236	246	256	266
12.0	12.6	13.2	13.8	14.4	15.0	15.6	16.2	16.8	17.4	18.0	18.6
68.0	76.0	78.0	84.0	90.0	99.0	104.0	108.0	106.0	111.0	116.0	121.0
94	108	128	142	155	165	178	191	209	219	229	238
17	18	18	18	18	18	18	18	19	19	19	19
191	215	237	258	277	297	316	333	351	366	382	397
44.1	44.1	44.1	44.1	44.1	44.1	44.1	44.1	44.1	44.1	44.1	44.1
100	100	100	100	100	100	100	100	100	100	100	100
144	144	144	144	144	144	144	144	144	144	144	144
-34	-49	-61	-71	-79	-86	-94	-100	-106	-111	-115	-119

Distributed Generating Capacity: This portfolio focuses on local generating capacity and adds important redundancy to the City's local distribution network. By deploying rooftop and fixed tilt solar, CHP in 5 area hospitals, CHP at other major city infrastructure locations, and microgrids the City is better able to respond to storm islanding. In this scenario, capacity resource acquisition is part of a coordinated effort with the New Orleans Redevelopment Authority, Sandia Labs, and private entities to build a more resilient New Orleans. Though CHP uses natural gas, it realizes greater energy returns from every unit of fuel and is therefore a cleaner option than a CT. Along with storm hardening for distribution and transmission to improve resilience to weather events, the distributed capacity offers greater confidence in New Orleans in the face of changing climate and rising sea levels.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
MW Requirements												
Base, LF, & Peak Load		1,125	1,136	1,143	1,153	1,159	1,163	1,175	1,183	1,193	1,201	1,209
Reserve Margin (12%)		135	136	137	138	139	140	141	142	143	144	145
Total MW Requirements		1,260	1,273	1,280	1,291	1,298	1,303	1,316	1,325	1,336	1,345	1,355
Existing Resources												
ENO and Algiers Resources		1162.6	1162.6	1153.6	1153.6	1152.6	1153.6	1153.6	1153.6	1153.6	1153.6	1153.6
Solar +Battery		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total Existing		1163.1	1162.6	1153.6	1153.6	1152.6	1153.6	1153.6	1153.6	1153.6	1153.6	1153.6
CAPACITY DEFICIT		97	110	126	137	145	149	162	171	182	191	201
LOAD SERVING DEFICIT		-38	-27	-11	-1	6	9	21	29	39	47	55
Planned Resources												
Sewage & Water Board Biogas CHP				3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Distributed Hospital CHP			8	16	24	32	40	40	40	40	40	40
Microgrids with Solar or CHP			5	10	15	20	25	25	25	25	25	25
Utility Scale Solar (1)			25	25	25	25	25	25	25	50	50	50
Rooftop Utility Solar			5.0	10.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Community Solar (2)			0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0	4.5	5.0
Residential Rooftop Solar (3)	6.9	7.4	7.9	8.4	9.0	9.6	10.2	10.8	11.4	12.0	12.6	13.2
DR (4)		5.0	10.0	17.0	24.0	29.0	37.0	46.0	56.0	68.0	76.0	78.0
Energy Smart Energy Efficiency Programs (4)		8	13	20	29	41	54	67	81	94	108	128
Voltage Reduction (5)		17	17	17	17	17	17	18	18	18	18	18
TOTAL ENO CAPITAL INVESTMENT		37	91	124	160	191	226	250	275	326	349	372
PPA Co-Generation Oxy (6)		50	50	50	50	50						
TOTAL PPA	0	50	50	50	50	50	50	50	0	0	0	0
Capacity Market Purchase Option		10	-31	-48	-72	-95	-126	-137	-104	-144	-158	-171

1. Utility scale solar capacity is discounted 25% based on MISO.
2. Community Solar capacity is discounted 25% based on MISO.
3. Rooftop solar capacity discount rate of 20% based on Lazard. Estimated growth is 7% based on ENO's estimate in the netmetering docket.
4. Energy Smart is based on EAI 0.31 ratio, these figures are calculated from a 2014 base year rather than the previous year's gross sales
5. Voltage reduction low case with 1.5% savings and VoltVar technology
6. 5 year PPA with Occidental Co-generation unit

*Note MW are cumulative

2027	2028	2029	2030	2031	2032	2033	2034	2035
1,220	1,230	1,241	1,251	1,261	1,271	1,281	1,291	1,301
146	148	149	150	151	153	154	155	156
1,366	1,378	1,390	1,401	1,412	1,424	1,435	1,446	1457
1144.6	1135.6	1153.6	1140.6	1130.6	1153.6	1153.6	1153.6	1153.6
0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
1144.6	1135.6	1153.6	1140.6	1130.6	1153.6	1153.6	1153.6	1153.6
221	242	236	260	281	270	281	292	303
75	94	87	110	130	117	127	137	147
3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
40	40	40	40	40	40	40	40	40
25	25	25	25	25	25	25	25	25
50	50	50	50	50	50	50	50	50
15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
13.8	14.4	15.0	15.6	16.2	16.8	17.4	18.0	18.6
84.0	90.0	99.0	104.0	108.0	106.0	111.0	116.0	121.0
142	155	165	178	191	209	219	229	238
18	18	19	19	19	19	19	19	20
393	412	433	452	469	486	501	517	533
0	0	0	0	0	0	0	0	0
-171	-170	-197	-191	-188	-215	-220	-225	-229

The three portfolios presented offers the City Council Members more options to realize their vision for a cleaner, safer, and affordable energy profile. The options presented give the City more flexibility and time to shape the future of New Orleans.

The Resiliency Rubric for the Portfolios

The Resiliency Rubric can be used as a guide for the City Council and Advisors to make decisions around the problems New Orleans faces in terms of future costs, environmental justice, and storm risks, among other resiliency concerns, and how the city should determine what resources are best within this context. Below are the criteria from Chapter 5 comparing the IResP resources. Again, it is the Alliance's hope that its proposed criteria will prompt a discussion on what resiliency means for the New Orleans energy system.

To refresh, the criteria includes:

"**Risk of Fuel Spikes**" This means that the generating plant uses a fuel source that is subject to global markets, such as coal, oil, or natural gas. If the plant uses natural gas, coal, or oil then the power plant gets a "Yes" for the risk.

"**Environmental Justice Score**" This column has been left blank because the Environmental Justice community has not had an opportunity to vet a formula for accuracy or efficacy. This is a placeholder because it is critically important.

"**Economic Impact to New Orleans**" The Alliance assumes that resources located in Orleans Parish offer more economic impact than resources outside of the parish. DSM and DR are known job-creating programs but they offer other indirect economic benefits. In Arkansas, the utility energy efficiency programs generated an estimated 9,000 jobs and $1 billion in sales.[2] The jobs created average more than $20.00 per hour for skilled labor and boosted locally owned, small businesses within the energy efficiency sector.

"**Ability to Provide Emergency Power**" Determines if the power plant is safe from any storm events geographically close to New Orleans. If the power plant is within 15 miles of New Orleans, then it received a "No", within 30 miles "Maybe", and beyond 30 miles the power plant received a "Yes". Hospital CHP is excluded because hospitals are not evacuated unless there is a mandatory evacuation order. Again, this labeling is for illustration purposes only and meant for discussion.

“**Offsets Transmission Islanding**” Power units received a “yes” if its location is within 30 miles of New Orleans. It is assumed that transmission lines that connect power plant resources within 30 miles of the city would retain functionality.

“**Flood Risk**” Criteria is based on the Flood Vulnerability Assessment Map created by the U.S. Energy Information Administration. The map overlays FEMA flood hazard maps with EIA’s critical energy infrastructure. If the power plant is located within a flood zone, then it received a “Yes”.[3]

As a reminder from chapter 5, the criteria in the Resiliency Rubric are not meant to be exclusive, simply illustrative. This is a much larger conversation that should include many more stakeholders including the utility.

Table 8.1: Supply-Side Resource Resiliency Rubric

Unit	**Risk of Fuel Spikes**	**EJ Score (1)**	**Economic Impact**	**Emergency Power**	**Offset Islanding**	**Risk of Flooding**
Oxy-Taft PPA	yes		medium	maybe	yes	no
Wind PPA	no		medium	yes	no	no
CHP	yes		high	yes	yes	no
Utility Solar	no		high	yes	yes	no
Microgrids with solar	no		high	yes	yes	no
Microgrids with CHP	yes		high	yes	yes	no
DSM/DR	no		high	no	no	no

Caveats

The portfolios are not to be interpreted as final IRP selections because they have not been modeled on hourly load. This filing is meant to be illustrative and show that other viable resources exist. The early coal retirements are a conceptual notion and not intended to represent specific options or limitations in the current contracts. Though we use LCOE, we were not able to model rate impacts. This is clearly the Council's responsibility and that of their advisors. In future modeling, it is recommended that rate impacts are balanced across the time horizon. We are not recommending going long on power, we simply wanted to show that there are plenty of options available to meet the need.

The assumptions, scenarios, sensitivities, criteria and portfolios evaluated in this filing are for consideration and discussion purposes. The Alliance does not claim that this IResP is a final word or solution to the complex decisions before the Council. The Alliance offers these portfolios as both a supplement and a contrast to ENO's IRP filing. It believes that fully explored portfolio options which account for realistic costs, both economic and external, should be the product of an IRP process that guides new resource acquisition. It is the Alliance's hope that this filing provides an example of what is possible for final IRP documents.

Final Recommendations

- Before any resources are approved, the DSM targets established in Resolution R-15-599 must be evaluated to determine their impact on future load projections and resource adequacy requirements
- Establish criteria that can be used to compare the resilience, environmental, and economic development impacts of various combinations of resource additions. The criteria will help the Council evaluate the diverse energy resources and consider the pros and cons of imported, local, and distributed generation resources.
- Complete the 2015 IRP without approving ENO's preferred portfolio.

Conclusion

The mix of generation, demand side management, and storage in the following portfolios offer cost-effective ways for New Orleans to meet its local power needs with built-in flexibility. The aim is to give the Council and their advisors real alternatives that better reflect the Council's stated clean energy goals. These resources are reflective of important recent trends in other utility jurisdictions and represent 21st century electricity strategies.

[1] Yale Climate Opinion Map (2014) Yale Project on Climate Change Communication and the George Mason Center for Climate Change Communication. Available at: http://environment.yale.edu/poe/v2014/

[2] HISTECON Associates, Inc. (2014) The Economic Impact of Energy Efficiency Programs in Arkansas: A Survey of Contractor Activity in 2013. Available at: http://arkansasadvancedenergy.com/files/dmfile/TheEconomicImpactofEnergyEfficiencyProgramsinArkansas.FINAL.pdf

[3] U.S. Energy Information Administration Flood Vulnerability Assessment Map Available here: http://www.eia.gov/special/floodhazard/

Appendix 1

A Note on the Symbiotic Relationship Between IRP & EERS

Many states have adopted EERS policies to supplement their IRP process and increase their energy efficiency impact.[3] The results are staggering: for states utilizing both IRP and an EERS achieved three times the energy savings compared to states without an EERS.[4] Additionally, states with an IRP but no EERS were not able to achieve more than 1% of its previous year's sales in 2013.[5]

Of particular importance in explaining why IRPs alone have not produced the energy efficiency savings is the treatment of energy efficiency in modeling software. Instead of treating efficiency as a demand side resource that is equal to supply resources, efficiency is typically shown in IRP models as lowering the demand that supply side resources must meet. ACEEE finds this does not optimize energy efficiency, but instead places artificial constraints on its performance.[6] Additionally, efficiency modeling results in IRP processes are not necessarily binding.[7] ACEEE finds that the IRP process is most effective at achieving energy savings when there are specific EERS targets already in place. Like other jurisdictions, New Orleans is best served with the combination of Integrated Resource Planning and established energy efficiency targets as proscribed by the City Council and enacted in Resolution No. R-15-599.

The existence of thirteen states with IRP processes that also have EERS indicates that the two do operate effectively together. Arizona provides a useful example of how the EERS and IRP proceedings fit together. While the EERS filing requirement is a standalone document, their IRP filings must contain information regarding the utility's energy efficiency plans to comply with the EERS. The legislative history from Arizona indicates the utility regulators believe providing energy efficiency programs is part of their duty to ensure that energy is provided at the lowest reasonable cost.[13] This is particularly important because EERS can ensure lower fuel costs, lower costs in generating facilities, operating expenses, and purchased power agreements.[14] The legislative history on the Arizona rules specifically state:

> *"The purpose of Electric Energy Efficiency Standards is for affected utilities to achieve energy savings through cost-effective energy efficiency programs in order to ensure reliable electric service at reasonable rates and costs. Energy efficiency means the production or delivery of an equivalent level and quality of end-use electric service using less energy, or the conservation of energy by end-use customers.*
>
> *"Requiring affected utilities to achieve energy savings through cost-effective energy efficiency programs is an essential part of the Commission's efforts to meet its constitutional obligation to [']prescribe just and reasonable rates and charges to be made and collected ... by public service corporations within the state for service rendered therein['] because the amount of energy consumed by an affected utility's customers, and the pattern of peak usage of those customers, directly impacts the physical assets that an affected utility must have in place as well as the affected utility's operating expenses. Reducing the overall consumption of energy can reduce fuel costs, purchased power costs, new capacity costs, transmission*

costs, distribution costs, and adverse environmental impacts (such as water consumption and air emissions). Even reducing peak demand without reducing overall consumption can reduce fuel costs, purchased power costs, and new capacity costs because not as much plant or purchased power is needed at peak times to meet customers' needs."[15]

[1] Kushler, Marty, and Maggie Molina. "Policies Matter: Creating a Foundation for an EE Utility of the Future", June 9, 2015. Pg. 7. Available at: http://aceee.org/policies-matter-creating-foundation-energy.
[2] Ibid.
[3] The Alliance has identified thirteen (13) states that have both an IRP and EERS: Arizona, Arkansas, Colorado, Hawaii, Iowa, Minnesota, Nevada, New Mexico, North Carolina, Oregon, Rhode Island, Vermont, and Washington.
[4] Kushler, Martin. "IRP v. EERS: There's a Clear Winner", December 16, 2014. Available at: http://aceee.org/blog/2014/12/irp-vs-eers-there%E2%80%99s-one-clear-winner-
[5] Policies Matter. Pg. 17.
[6] Ibid.
[7] Ibid.
[8] "IRP v. EERS: There's a Clear Winner." In particular, in Policies Matter, ACEEE finds that those states without EERS that have an IRP have an average savings of .3% and those states without either have an average energy savings of .2%. Policies Matter pg. 18.
[9] Schlegel, Jeff and Ellen Zuckerman. "No Longer Background Noise". Available at: https://www.tep.com/doc/planning/SWEEP-ACEEE_EE&IRP_Zuckerman1146.pdf
[10] Ibid.
[11] Ibid.
[12] Ibid.
[13] See 2010 AZ REG TEXT 210938 (NS). Notices of Final Rulemaking, November 26, 2010.
[14] Ibid.
[15] 2010 AZ REG TEXT 210938 (NS). Notices of Final Rulemaking, November 26, 2010.

Appendix 2.

New Orleans energy efficiency scenario

		2011	2012	2013	2014	2015
EnergySmart, Entergy New Orleans verified program savings						
1 Incremental annual savings (kWh)		15,842,339	20,572,422	16,007,993	16,449,016	
Incremental annual savings (GWh)		15.8	20.6	16.0	16.4	
Verified demand savings (kW)		3,137	3,366	3,123	3,395	4114
Verified demand savings (MW)		3.1	3.4	3.1	3.4	-
Ratio of peak savings to annual elec savings (MW/GWh)		*0.20*	*0.16*	*0.20*	*0.21*	*0.23*
Incremental annual savings (kWh)		15,812,955	20,572,422	16,007,993	16,449,016	17,838,583
Sales (kWh)		5,122,384,000	5,011,659,000	5,107,748,000	5,232,742,000	
Sales (GWh)		5,122	5,012	5,108	5,233	5,392
Savings as % of sales; targets 2015-2035		0.31%	0.41%	0.31%	0.31%	0.33%
						<----actual
average ratio of peak savings to elec savings (MW/GWh)	*0.19*					
Entergy Arkansas ratio of peak to savings (MW/GWh) for entire portfolio in 2014	*0.31*					

Estimated energy and peak demand savings impacts from Council's recommendation

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Targets (%)		0.5%	0.7%	0.9%	1.1%	1.3%	1.5%	1.7%	1.9%	2.0%	2.0%	2.0%	2.0%	2.0%
Sales forecast, per ENO ref case (GWh)	5,406	5,535	5,540	5,590	5,643	5,695	5,739	5,792	5,848	5,913	5,968	6,026	6,085	6,149
Sales forecast, modified for EE impacts		5,360	5,452	5,410	5,405	5,394	5,375	5,341	5,309	5,280	5,266	5,245	5,231	5,221
Incremental annual savings (GWh)	18	29	39	51	61	72	83	93	103	106	106	105	105	105
Total annual (cumulative) electricity savings (GWh)	18	46	83	130	185	249	320	398	483	568	647	723	795	864
Estimated peak demand savings, at site														
Energy efficiency savings (% of all peak savings)	*64%*	*58%*	*56%*	*54%*	*55%*	*58%*	*59%*	*59%*	*59%*	*58%*	*59%*	*62%*	*63%*	*63%*
Demand response savings (% of all peak savings)	*36%*	*42%*	*44%*	*46%*	*45%*	*42%*	*41%*	*41%*	*41%*	*42%*	*41%*	*38%*	*37%*	*37%*
Total annual savings, 0.19 ratio	3	9	16	25	35	47	61	76	92	108	124	138	152	165
Energy efficiency (MW)	*2*	*5*	*9*	*13*	*19*	*28*	*36*	*45*	*55*	*63*	*73*	*86*	*95*	*104*
Demand response (MW)	*1*	*4*	*7*	*11*	*16*	*20*	*25*	*31*	*38*	*45*	*51*	*52*	*57*	*61*
Total annual savings, 0.31 ratio	5	14	25	40	57	76	98	122	148	174	198	222	244	265
Energy efficiency (MW)	*4*	*8*	*14*	*22*	*31*	*44*	*58*	*72*	*88*	*101*	*117*	*138*	*153*	*167*
Demand response (MW)	*2*	*6*	*11*	*18*	*26*	*32*	*40*	*50*	*60*	*73*	*82*	*84*	*91*	*97*
Average of 0.19 ratio and 0.31 ratio values														
Total annual savings, 0.25 ratio		*11*	*21*	*32*	*46*	*62*	*80*	*99*	*120*	*141*	*161*	*180*	*198*	*215*
Energy efficiency (MW)		*7*	*11*	*18*	*25*	*36*	*47*	*59*	*71*	*82*	*95*	*112*	*124*	*136*
Demand response (MW)		*5*	*9*	*15*	*21*	*26*	*33*	*40*	*49*	*59*	*66*	*68*	*74*	*79*
Peak demand savings, at generation (MW)														
Total annual savings, 0.19 ratio		*10*	*18*	*28*	*40*	*54*	*70*	*87*	*105*	*124*	*141*	*158*	*174*	*189*
Energy efficiency (MW)		6	10	15	22	32	41	51	62	72	83	98	109	119
Demand response (MW)		4	8	13	18	23	29	36	43	52	58	60	65	69
Total annual savings, 0.31 ratio		16	*29*	*46*	*65*	*87*	*112*	*140*	*170*	*199*	*227*	*254*	*279*	*303*
Energy efficiency (MW)		*9*	*16*	*25*	*36*	*51*	*66*	*83*	*100*	*116*	*133*	*158*	*175*	*192*
Demand response (MW)		*7*	*13*	*21*	*29*	*36*	*46*	*57*	*69*	*84*	*94*	*96*	*104*	*111*
Average of 0.19 ratio and 0.31 ratio values														
Total annual savings, 0.25 ratio		*13*	*24*	*37*	*53*	*71*	*91*	*113*	*138*	*161*	*184*	*206*	*226*	*246*
Energy efficiency (MW)		*8*	*13*	*20*	*29*	*41*	*54*	*67*	*81*	*94*	*108*	*128*	*142*	*155*
Demand response (MW)		*5*	*10*	*17*	*24*	*29*	*37*	*46*	*56*	*68*	*76*	*78*	*84*	*90*

IRP Table 28: ENO Preferred Portfolio Stakeholder Input Case--Load & Capability 2015-2035 (All values in MW)

Requirements	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Peak load	1,125	1,136	1,143	1,153	1,159	1,163	1,175	1,183	1,193	1,201	1,209	1,220	1,230
Reserve margin (12%)	135	136	137	138	139	140	141	142	143	144	145	146	148
Total Requirements	1,260	1,272	1,280	1,291	1,298	1,303	1,316	1,325	1,336	1,345	1,354	1,366	1,378
DSM	7	12	18	25	34	44	52	60	64	69	75	78	81

2015 ENO IRP http://www.entergy-neworleans.com/content/IRP/2015_IRP_Final_Report.pdf
ENO Load Forecast Comparison of Scenarios, p. 65

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Energy Forecast (GWh)														
Industrial Renaissance	5,406	5,535	5,540	5,590	5,643	5,695	5,739	5,792	5,848	5,913	5,968	6,026	6,085	6,149
Business Boom	5,568	5,745	5,764	5,820	5,875	5,929	5,975	6,030	6,089	6,155	6,213	6,273	6,334	6,400
Generation Shift	5,375	5,450	5,493	5,521	5,544	5,567	5,598	5,651	5,708	5,772	5,827	5,885	5,945	6,008
Distributed Disruption	5,383	5,516	5,528	5,577	5,622	5,660	5,680	5,707	5,739	5,777	5,796	5,810	5,823	5,840
Total Peak Load Forecast (MW)														
Industrial Renaissance	1,029	1,050	1,049	1,059	1,064	1,070	1,075	1,081	1,088	1,096	1,105	1,112	1,120	1,128
Business Boom	1,052	1,078	1,079	1,089	1,095	1,101	1,107	1,113	1,120	1,128	1,137	1,145	1,153	1,161
Generation Shift	1,027	1,041	1,048	1,058	1,062	1,067	1,072	1,078	1,085	1,093	1,104	1,109	1,117	1,125
Distributed Disruption	1,029	1,049	1,048	1,057	1,063	1,068	1,072	1,076	1,083	1,089	1,099	1,103	1,108	1,115
Total Firm Peak Load Forecast (MW)														
Industrial Renaissance	1,006	1,026	1,026	1,035	1,040	1,046	1,051	1,057	1,064	1,072	1,081	1,088	1,096	1,104
Business Boom	1,028	1,055	1,056	1,065	1,071	1,077	1,083	1,089	1,096	1,104	1,113	1,121	1,129	1,137
Generation Shift	1,003	1,017	1,025	1,034	1,038	1,043	1,048	1,054	1,061	1,069	1,080	1,085	1,093	1,101
Distributed Disruption	1,005	1,025	1,025	1,034	1,039	1,044	1,048	1,053	1,059	1,065	1,075	1,079	1,084	1,091

Industrial Renaissance (Reference) – Assumes the U.S. energy market continues to grow with reference fuel prices. Current fuel prices drive load growth and economic opportunity in the region. The Industrial Renaissance scenario assumes reference load, reference gas and no CO2 costs.

Business Boom – Assumes the U.S. energy boom continues with low gas and coal prices. Low fuel prices drive high load growth. A modest CO2 tax or cap and trade program is implemented beginning in 2023.

Distributed Disruption – Assumes states continue to support distributed generation. Consumers and businesses have a greater interest in installing distributed generation, which leads to a decrease in energy demand at the customer's meter. Overall economic conditions are steady with moderate GDP growth, which enables investment in energy infrastructure. However, natural gas prices are driven higher by EPA regulation of hydraulic fracturing. Congress or the EPA also implements a moderate CO2 tax or cap and trade program.

Generation Shift – Assumes government policy and public interest drive support for government subsidies for renewable generation and strict rules on CO2 emissions. High natural gas exports and more coal exports lead to higher fuel prices.

Notes/Sources

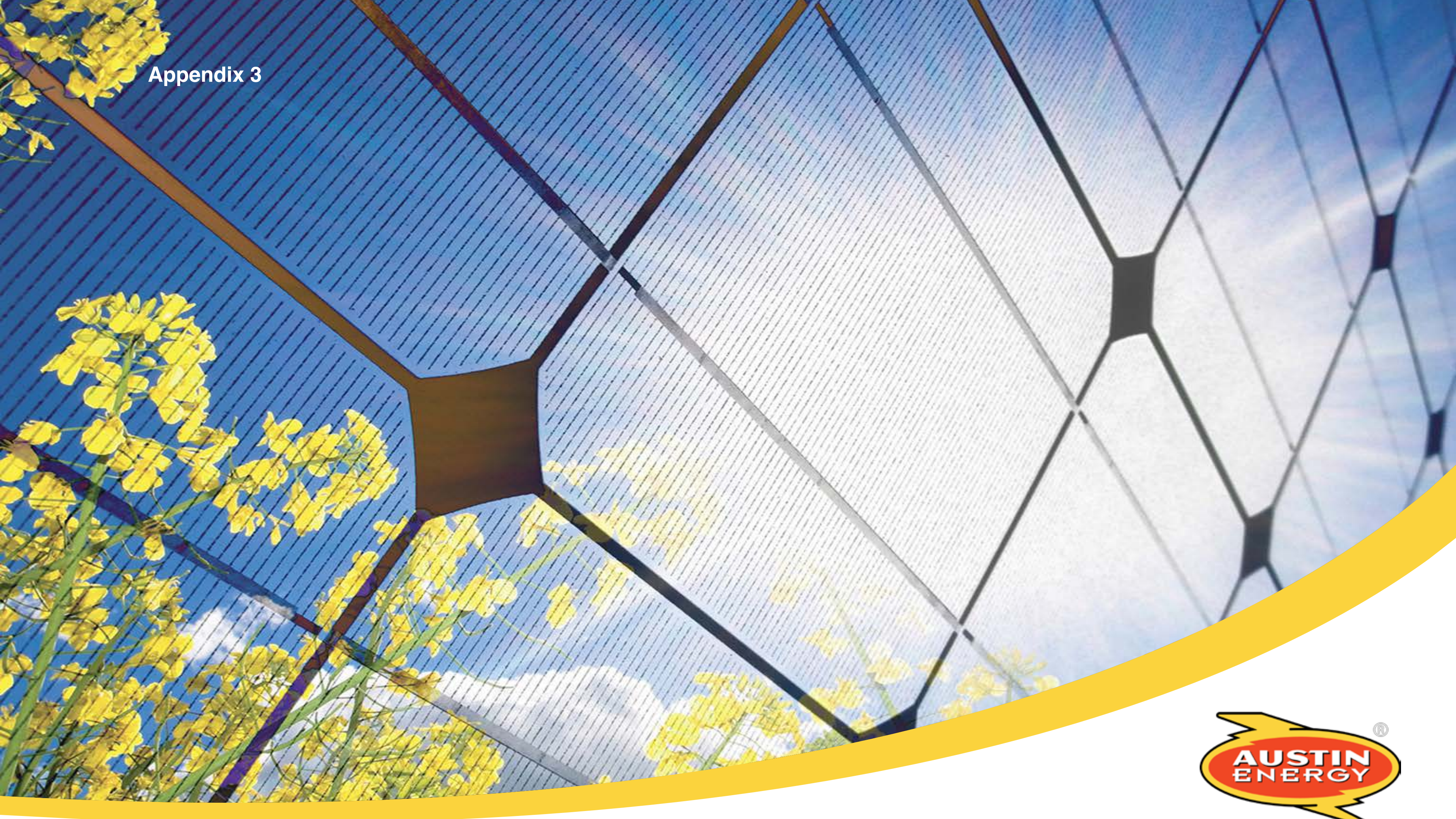
Year 1, 2011-2012 data, Table E.1	http://www.entergy-neworleans.com/content/docs/NOLA_Impact_2011_Evaluation_Appendix_C.pdf
Year 2, 2012-2013 data	http://www.entergy-neworleans.com/content/docs/2013_0621_Energy_Smart_Year_2_Annual_Rpt_Algiers_Quarterly_Rpt.pdf
Year 3, 2013-2014	http://www.entergy-neworleans.com/content/docs/2014_ENO_Energy_Smart_Year_3_Annual_Report.pdf
Year 4, 2014-2015 data, P. 5	http://www.entergy-neworleans.com/content/docs/2015_Energy_Smart_Annual_Filing_Year_4.pdf

2029	2030	2031	2032	2033	2034	2035
2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
6,201	6,258	6,318	6,382	6,438	6,497	0
5,220	5,210	5,208	5,211	5,221	5,226	5,235
104	104	104	104	104	104	105
929	991	1,050	1,107	1,161	1,212	1,262
63%	*63%*	*64%*	*66%*	*66%*	*66%*	*66%*
37%	*37%*	*36%*	*34%*	*34%*	*34%*	*34%*
177	189	200	211	221	231	241
111	*120*	*128*	*140*	*147*	*153*	*160*
66	*69*	*72*	*71*	*75*	*78*	*81*
285	304	322	339	356	372	387
178	*192*	*205*	*225*	*236*	*246*	*256*
107	*112*	*117*	*114*	*120*	*125*	*130*
231	*246*	*261*	*275*	*289*	*301*	*314*
145	*156*	*167*	*183*	*191*	*200*	*208*
86	*91*	*95*	*93*	*97*	*102*	*106*
203	*216*	*229*	*242*	*253*	*265*	*275*
127	137	146	160	168	175	182
76	79	83	81	85	89	93
326	*348*	*368*	*388*	*407*	*425*	*443*
204	*220*	*235*	*257*	*270*	*282*	*293*
122	*128*	*133*	*131*	*137*	*143*	*149*
264	*282*	*299*	*315*	*330*	*345*	*359*
165	*178*	*191*	*209*	*219*	*229*	*238*
99	*104*	*108*	*106*	*111*	*116*	*121*

2029	2030	2031	2032	2033	2034	2035
1,241	1,251	1,261	1,271	1,281	1,291	1,301
149	150	151	153	154	155	156
1,390	1,401	1,412	1,424	1,435	1,446	1,457
80	82	83	86	87	88	88

2029	2030	2031	2032	2033	2034	CAGR
6,201	6,258	6,318	6,382	6,438	6,497	0.97%
6,454	6,514	6,575	6,642	6,701	6,762	1.03%
6,060	6,117	6,177	6,241	6,297	6,356	0.89%
5,844	5,842	5,828	5,816	5,798	5,779	0.37%
1,136	1,143	1,152	1,160	1,168	1,176	0.71%
1,170	1,178	1,187	1,195	1,203	1,212	0.75%
1,134	1,141	1,151	1,156	1,165	1,173	0.70%
1,123	1,127	1,141	1,138	1,144	1,151	0.59%
1,112	1,119	1,128	1,136	1,144	1,152	0.72%
1,145	1,153	1,162	1,170	1,179	1,188	0.76%
1,109	1,116	1,127	1,132	1,141	1,149	0.72%
1,099	1,103	1,116	1,113	1,120	1,127	0.60%

Appendix 3



Investing in a Clean Future

Austin Energy's Resource, Generation and Climate Protection Plan to 2020 Updates

Council Committee on Austin Energy

December 4, 2014

2014 Resource Plan Update

Khalil Shalabi, Vice President, Resource Planning and Energy Market Operations

Highlights

- A process for looking into the future
- Progress to date
- Observations and drivers for planning results
- Additional scenarios to the 500+ plan
- Economic and affordability results
- Conclusions
- Impact of an additional 100MW local solar
- Recommendation
- Leadership amongst peers
- Appendix

Generation Plan Process – Looking Forward

- A measured system of choices and milestones over time

1. Set general direction by policy – City Council with advice from Austin Energy and stakeholders
2. Establish future path and milestones through Generation Plan
3. Pursue Generation Plan through budget, capital improvement plan, and financial strategies
4. Implement decisions through request for Council actions after competitive purchasing processes
5. 2-year updates to Generation Plan – allows for change in direction due to new inputs, market & regulatory forces, and stakeholder preferences

City Council will have numerous future approval steps in implementing the approved resource plan

Progress to date

- AE starts stakeholder process in February to gather input to update the 2010 resource plan to be issued in September
- Council forms and appoints members to the Generation Task Force (GTF) in April
- GTF issues report in June
- Resolutions 20140828-157 and 20140828-158 issued by Council in August
- AE presents affordability analysis for resolution 157 in September
- AE presents results of resource plan in October and recommends 500+ plan
- AE works with stakeholders on variations to the 500+ plan

Observations and Drivers for Resource Plan Results

- Affordability is dependent on keeping existing generation in service or replacing with new efficient gas generation. Both cost and risk improve with the efficiency and size of the replacement unit(s).
  - Location matters, the closer generation is to the Austin load zone the better

- A significant amount of renewable energy can be added economically with a marginal improvement to cost and risk if a gas fleet is maintained. This is not the case, however, if renewables are added and the gas fleet is retired without replacement. In this case, both cost and risk are increased.
  - The optimal amount of renewable energy for Austin Energy is around 50% of its load obligations; greater amounts result in diminishing returns

- Overall CO2 emissions are not affected by changes to Austin Energy's gas fleet. The retirement or addition of gas owned by AE will either be replaced by underutilized generation or displace less efficient generation within ERCOT. In other words, AE is too small a fish to affect the larger ERCOT market (i.e. ~4 percent).

Austin Energy 500+ Plan:

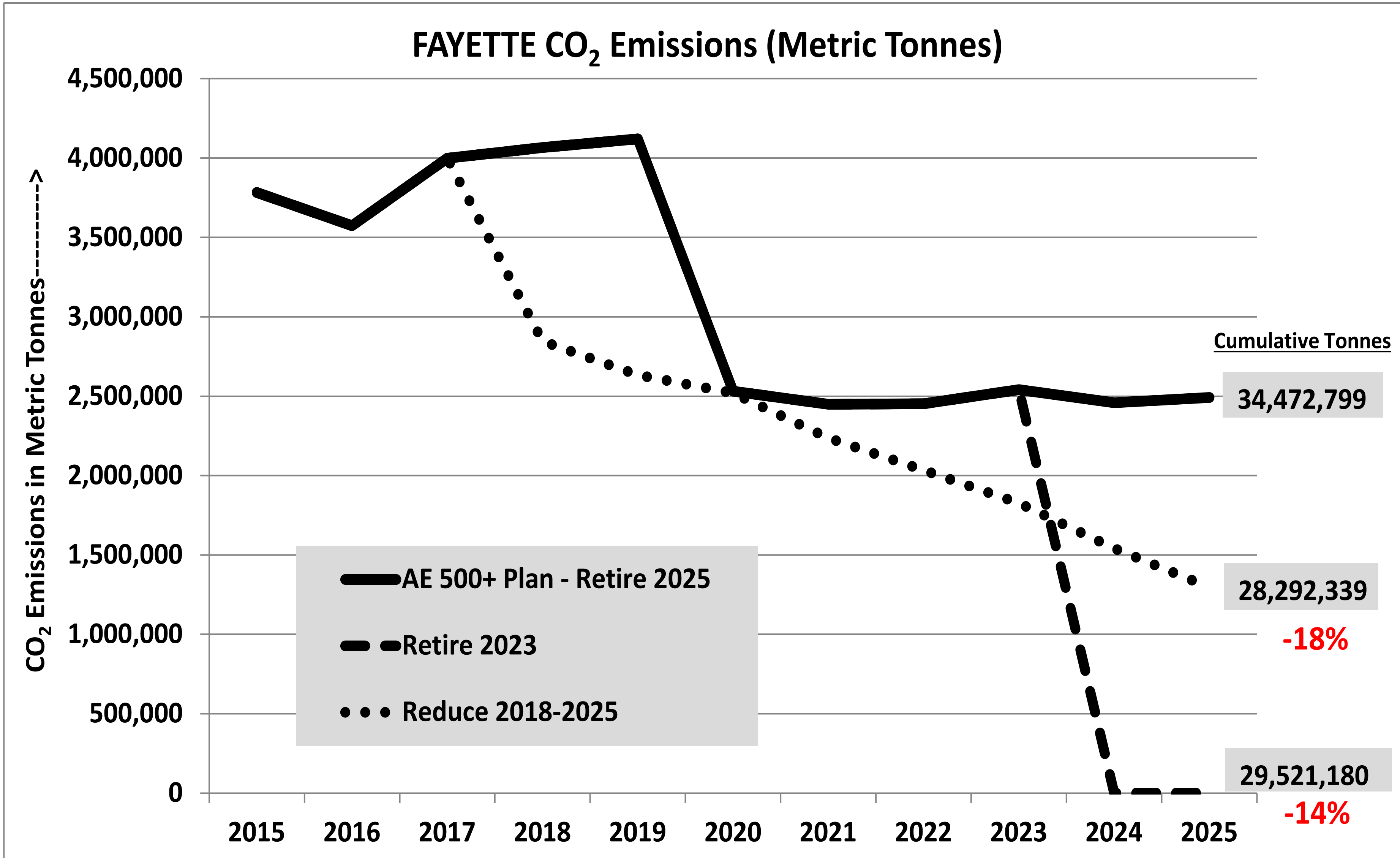
- Acquire 500 MW of solar, a 250% increase
- Add 375 MW of wind to achieve 50% renewables by 2025
- Reduce FPP output beginning in 2020, retire FPP in 2025
- Retire existing Decker steam plants by 2019
- Add 500 MW of highly efficient gas generation at Decker site
- Do not expand Sand Hill combined cycle unit
- Add grid-scale storage as technology and prices improve

Variations to Austin Energy 500+ Plan:

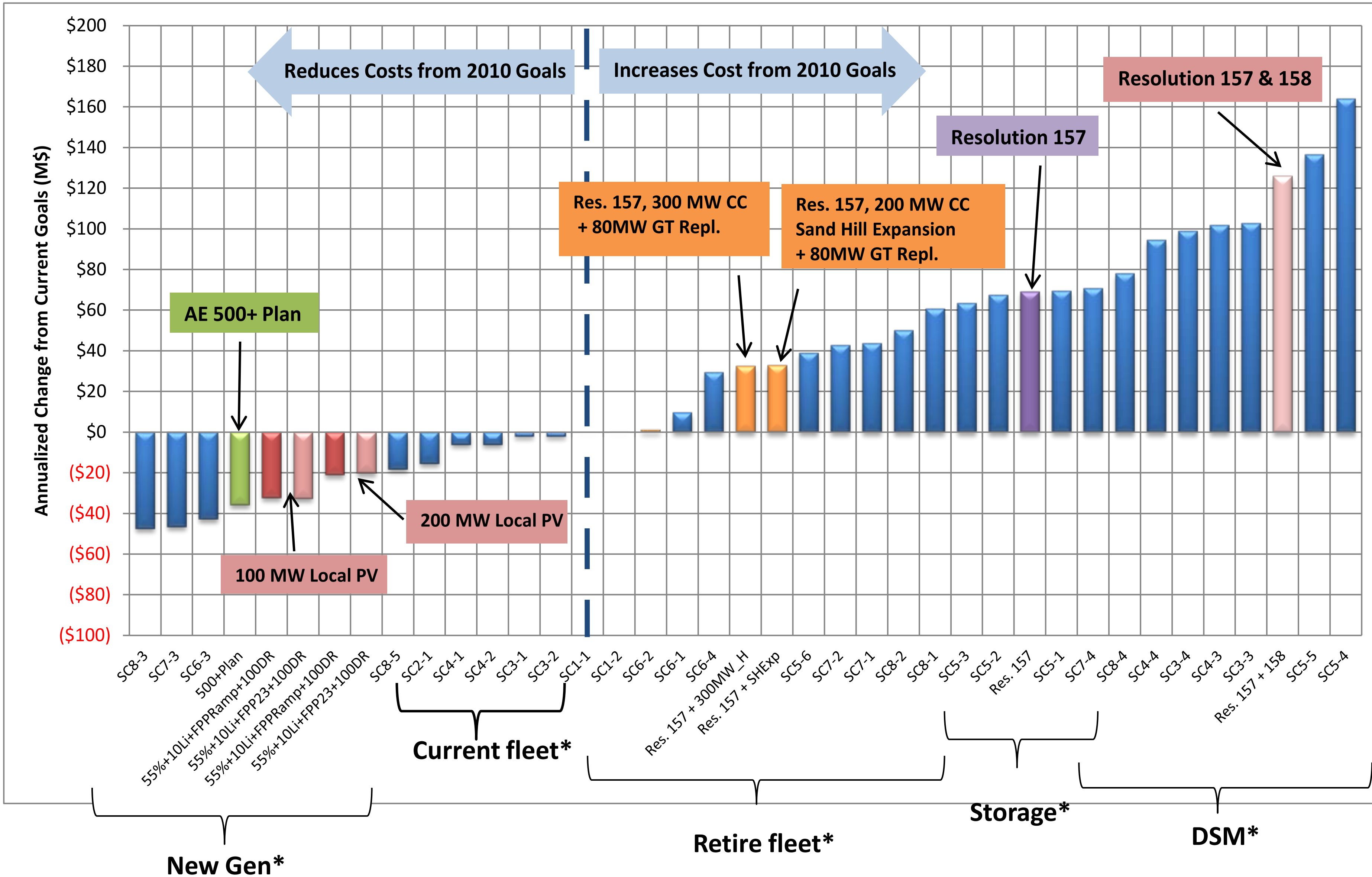
- 500+ 55% + 10 Li + FPP 2022 + 100 DR + (100/200 local):
  - Increase to 55% renewables by 2025
    - ✓Additional 100 MW of West Texas Solar
    - ✓Additional 75 MW of Wind
  - 10 MW (Lithium Ion batteries) of local storage by 2025 + 20MW of thermal storage
  - Retire FPP starting in 2022
  - 100 MW of new demand response by 2025
    - ✓Approximately 20 MW per year beginning in 2021
  - Local Solar sensitivities with 100 MW vs. 200 MW

- 500+ 55% + 10 Li + FPP Ramp + 100 DR + (100/200 local):
  - Same as above, except gradual ramp down of FPP beginning in 2018 (8% to 10% per year) then retired by 2025

FPP Emissions Reduction Scenarios
Retire in 2023 vs Gradual Ramp Down

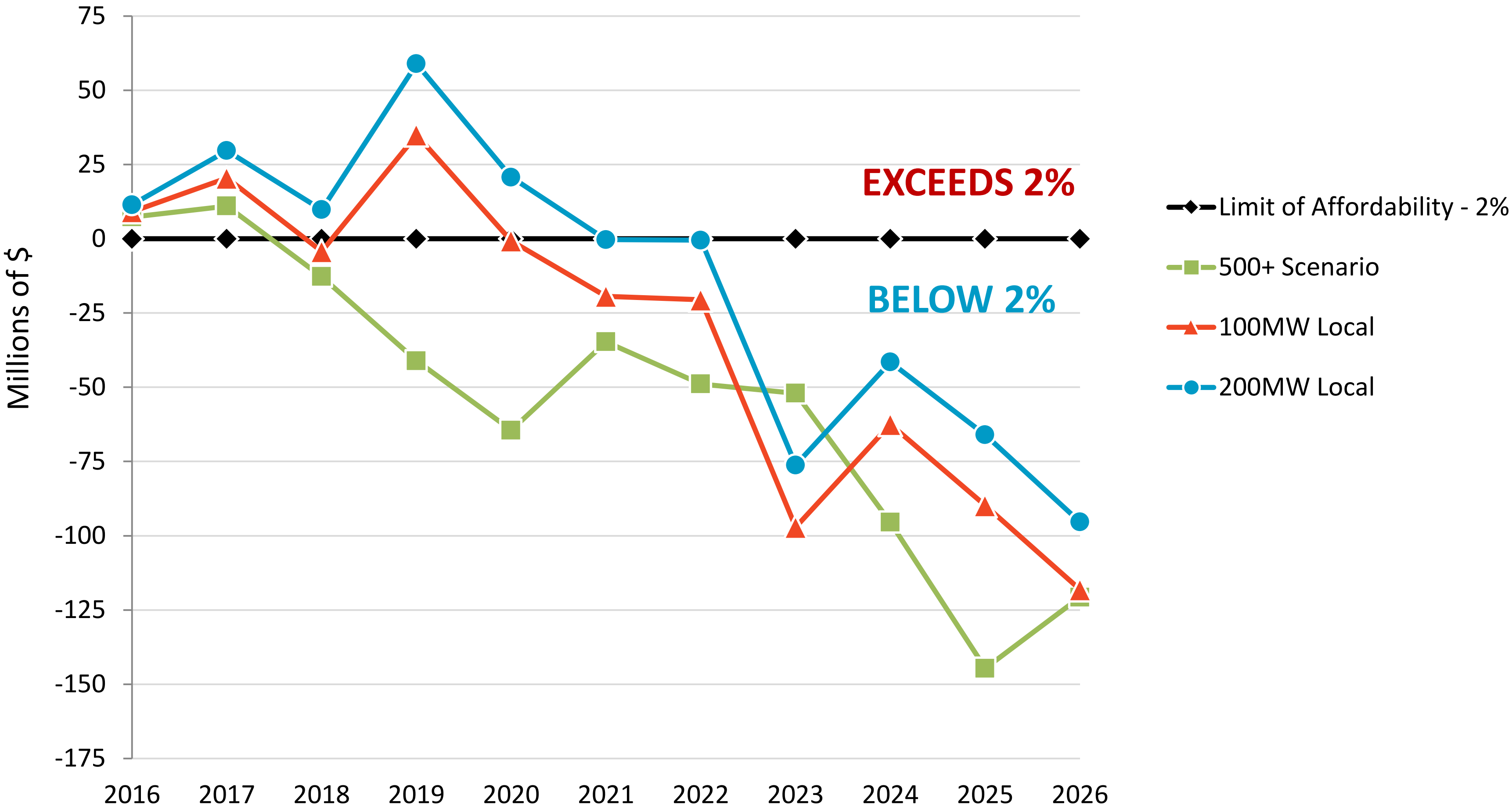


Yearly Change from 2010 Goals in $Millions per year

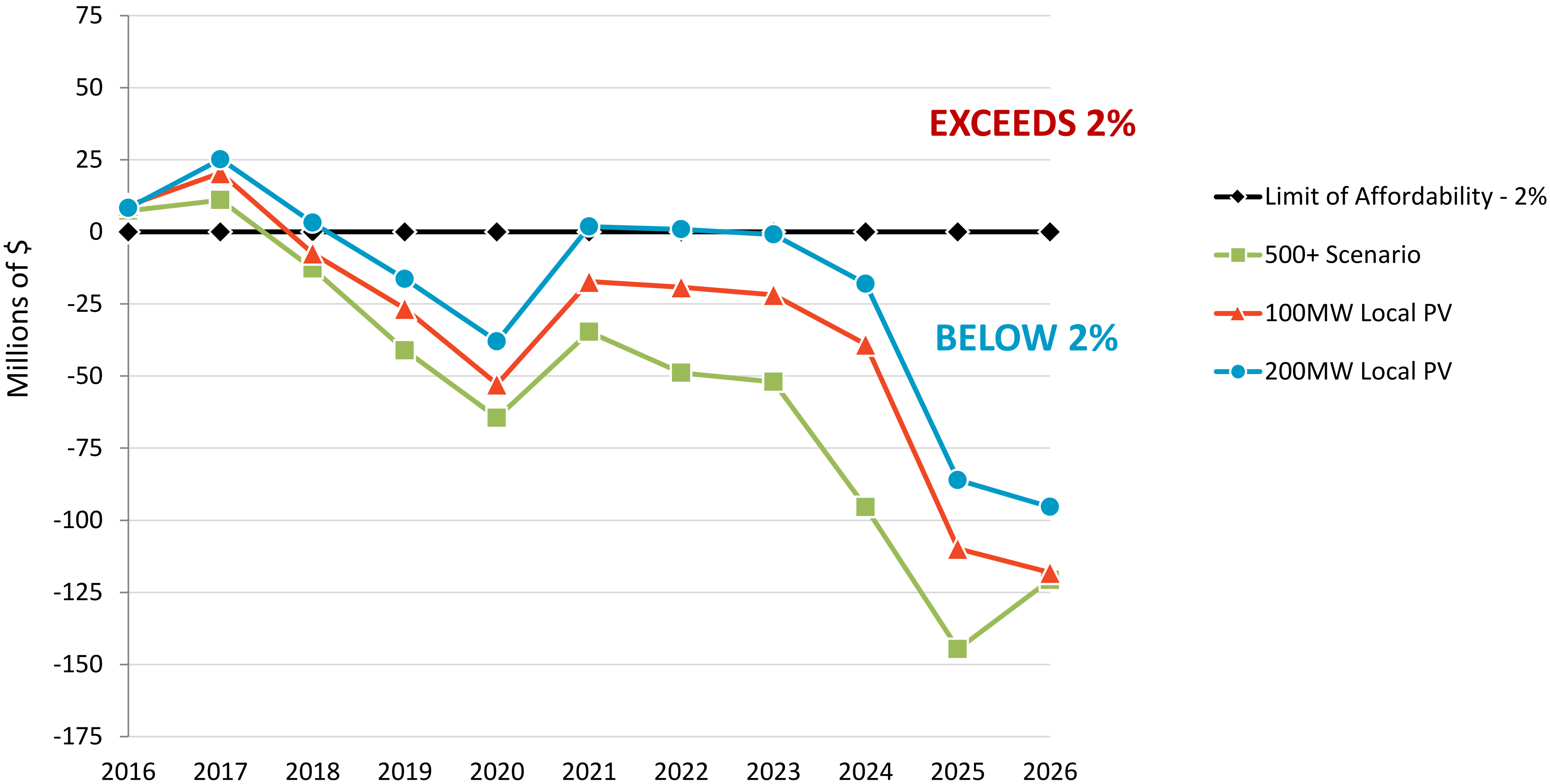


* - Major drivers

Austin Energy 500+ 55% + 10 Li + FPP 2022 + 100 DR + (100/200 local): Affordability Chart



Austin Energy 500+55% + 10 Li + FPP Ramp + 100 DR + (100/200 local): Affordability Chart



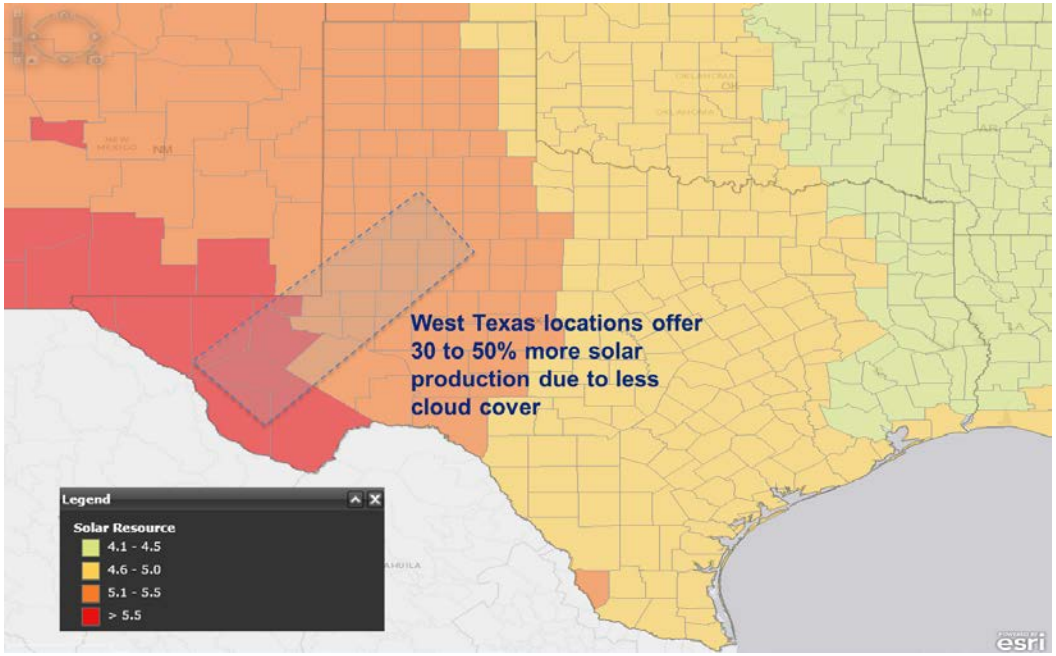
Conclusions from variations on 500+ plan

- 500 + Plan:
  - Early bumps in 2016/2017 due to capital on new plant and decker retirement
  - New plant revenues start in 2018 driving rates down through 2020
  - FPP retirement account drives rates up in 2020 but still affordable due to 500 CC revenues
  - Capital on new utility solar in 2019/2022/2025
  - Loss of FPP revenues are seen in 2025 but rates still stable due to 500 CC
- Early 2022 FPP Retirement
  - Earlier FPP collection and additional wind/solar for 55% drives rates up in 2019 above affordability
  - Incremental DR felt in 2021
  - Loss of FPP revenues comes earlier in 2023
  - Increased 100MWs of local solar keeps rates above affordability for the next few years
- Gradual FPP Retirement
  - Similar dynamics as above but maintains affordability

Cost of Local Solar versus Utility Scale Solar

- While distributed solar can reduce transmission costs and provide local economic development benefits, the cost per kW, and per kWh, is significantly higher than utility-scale solar
  - Utility-scale solar is less expensive due to economies of scale, and ability to locate in areas with better solar resource, such as West Texas
  - Customer-sited solar has a higher installed cost, and receives substantial subsidies from Austin Energy ratepayers, along with Value of Solar payments

	Rooftop Solar (residential)	Utility Scale (W. Texas)
Installed cost	\$3.00-\$4.25/W	\$1.75-\$2.25/W
Cost to utility	\$0.107/kWh	\$0.05/kWh
Additional rebate	\$1.10/W = ~3.5 cents/kWh over 25 yrs	-



Recommendation

The plan adopts and acts immediately on:

- Commencing a project to replace Decker steam units with a 500MW highly efficient gas plant contingent on an independent review and council approval
- Issuing an RFP for 600MW of utility scale solar to commence the process towards a generation portfolio consisting of 55% renewable energy.
- Maintaining the current goal of 800 MWs of EE and DR by 2020, and adding an incremental 100 MWs of DR to achieve a total of at least 900 MWs of DSM by 2024.
- Implementation plan for distribution connected local storage of at least 10 MWs complemented by as much as 20MWs of thermal storage.
- Create cash reserve fund for FPP retirement approved through the regular budgeting process and targeted to retire Austin's share of the plant beginning in 2022

Recommendation - Continued

- The Plan also recommends the following contingent upon further study, technological development, progress towards goals and rate adjustments or restructuring:

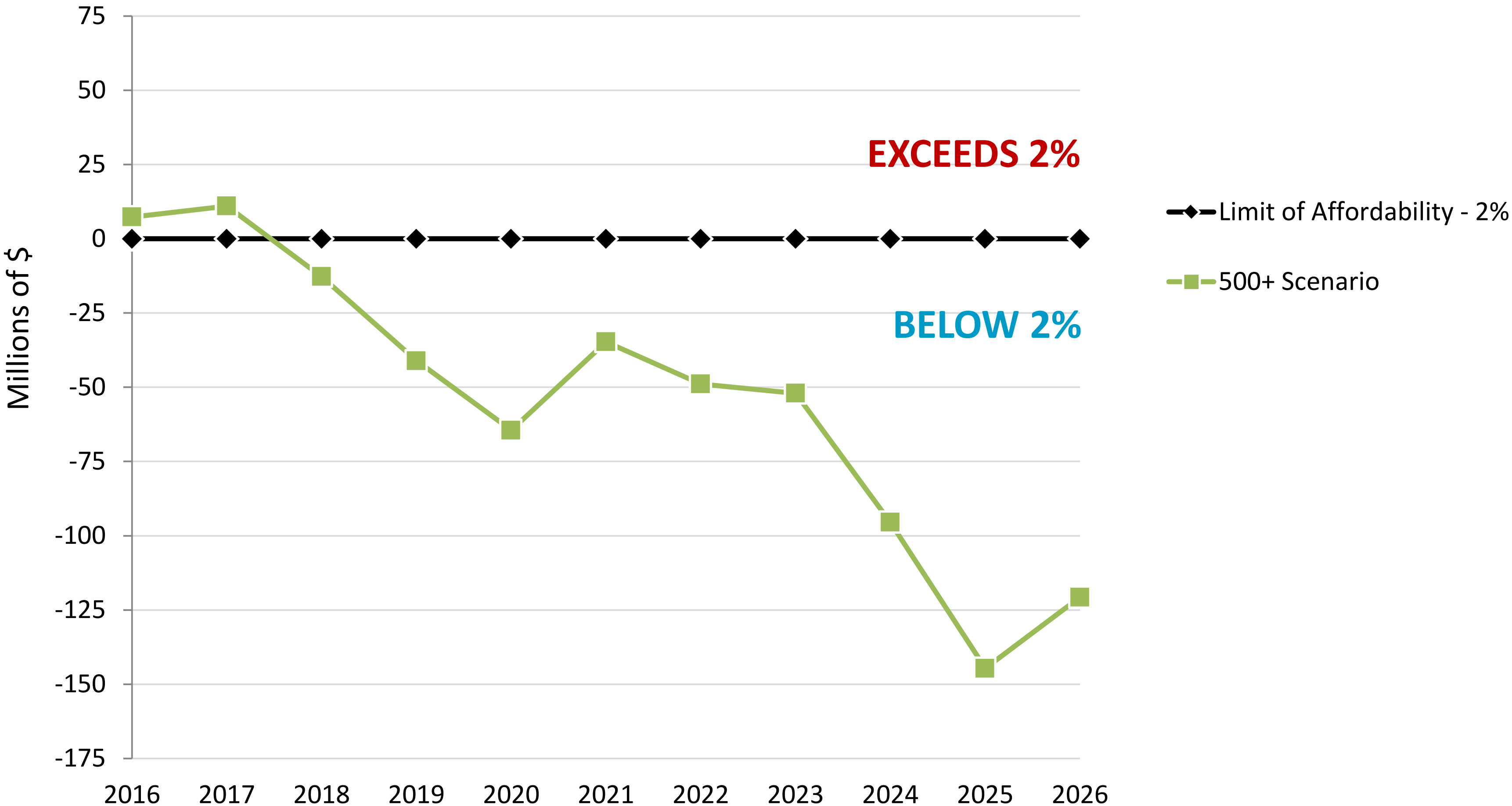
  – An additional 100MWs of DR or EE to increase the DSM achieved to 1000MWs by 2025
  – An additional 100MWs of local solar for a local solar portfolio of 200MWs contingent upon development of rate structure that maintains equity amongst customers
  – Issuing an RFI for 170 MWs large scale storage such as Compressed Air Energy Storage

Leadership

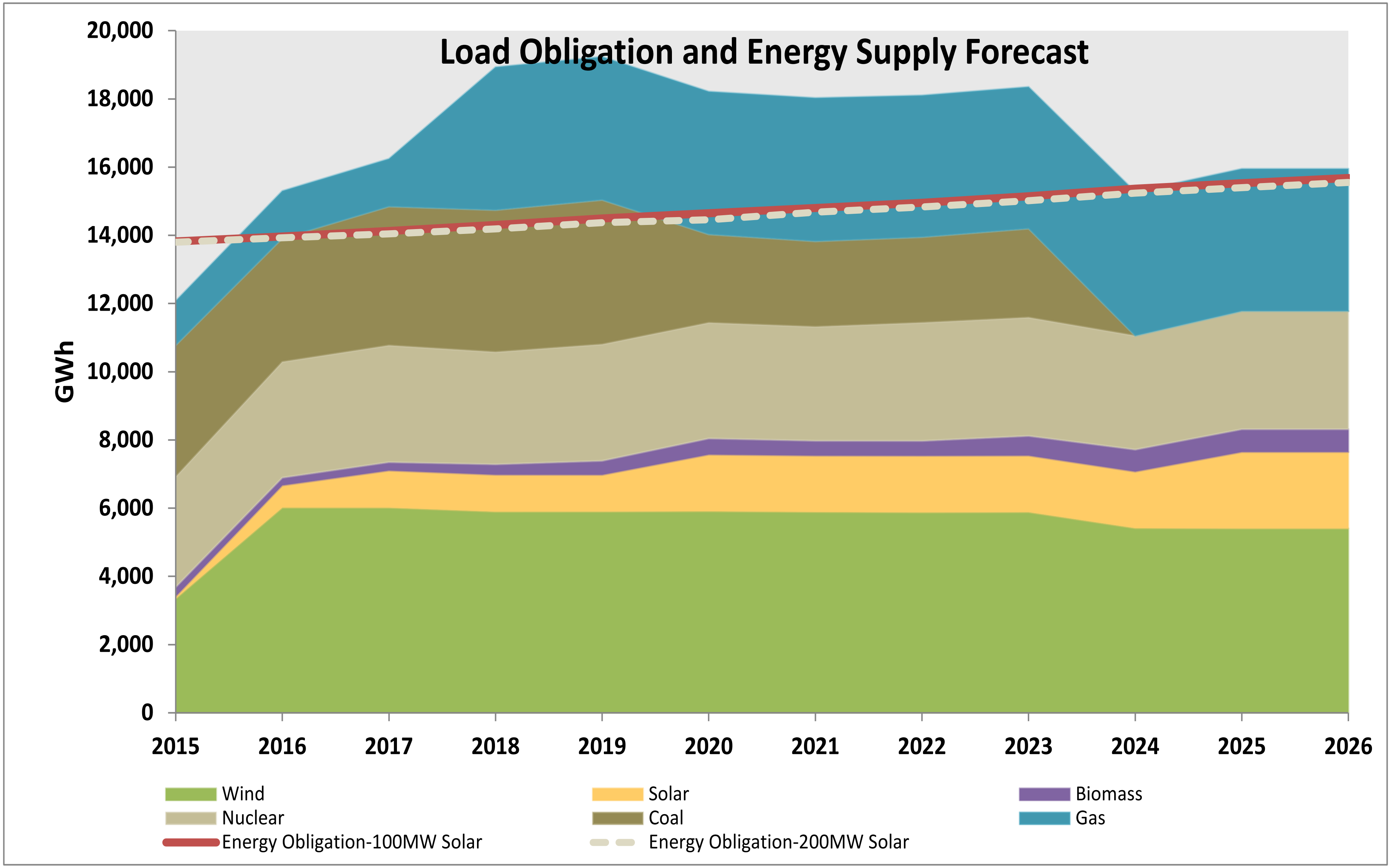
Plan Attribute	2020 Plan	2025 Plan	Improvement	Leadership
% Renewable	35%	55%	71% increase	Exceeds leading state goals (Hawaii 40%) and top European goals (Germany/Sweden 50%)
Solar	200 MWs	950 MWs	375% increase	If Austin were a state it would rank second behind CA
Wind	1200	1575	31% increase	Austin will have 14% share of Texas wind, 3.5x its load share
DSM	800	900	12% increase	Covers 3 years of peak demand growth
Fossil Fuel	Fleet as is	Retire FPP coal & Decker gas, add 500MW gas CC	36% decrease	Nearly 80% carbon free
Storage	NA	30 MWs	NA	Nearly equal to ERCOT's current installed battery storage (34 MW)

Appendix

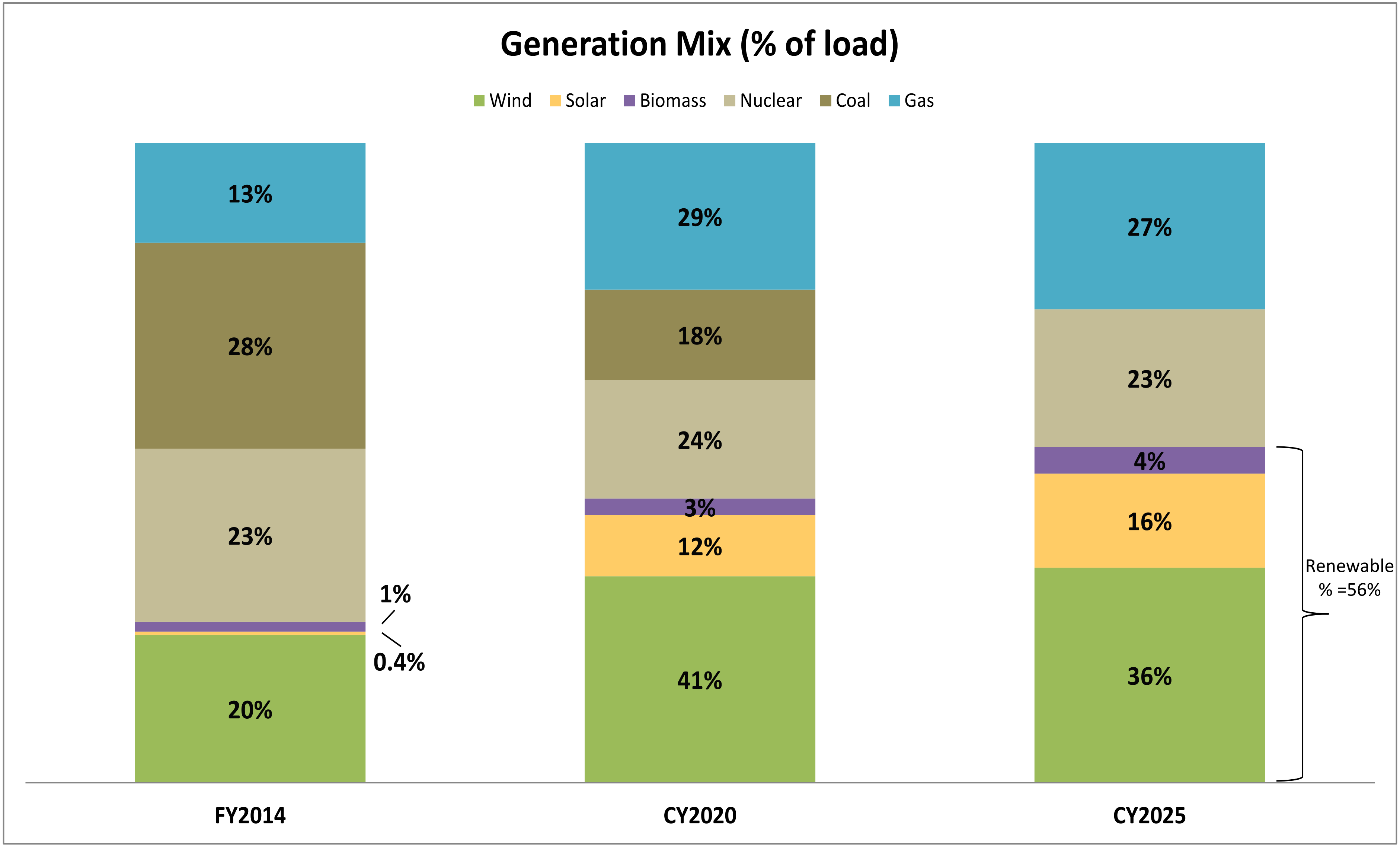
Austin Energy 500+ Scenario Affordability Chart



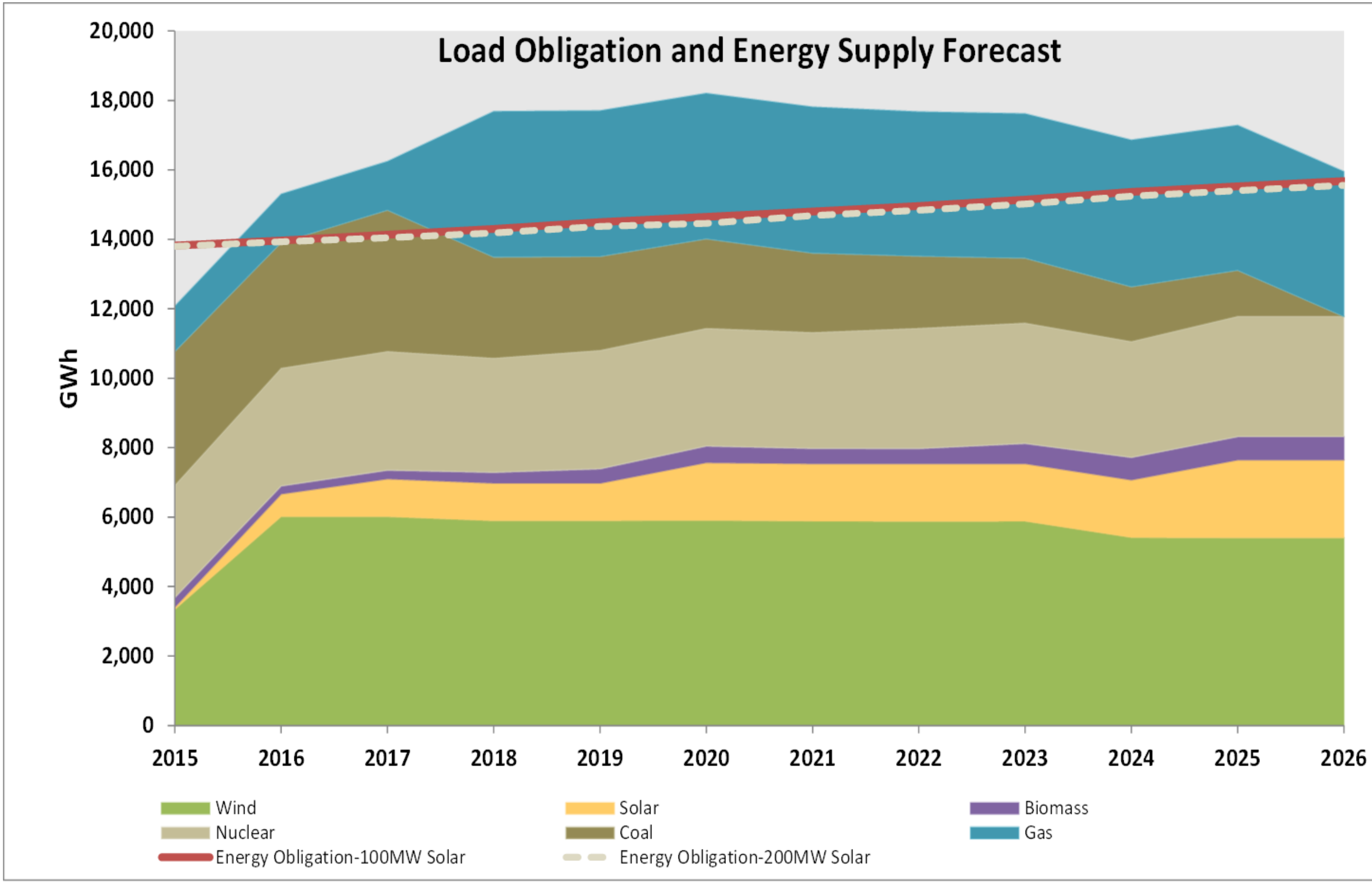
Energy Supply with
500+ 55% + 10 Li + FPP 2023 + 100 DR + 100/200 Local



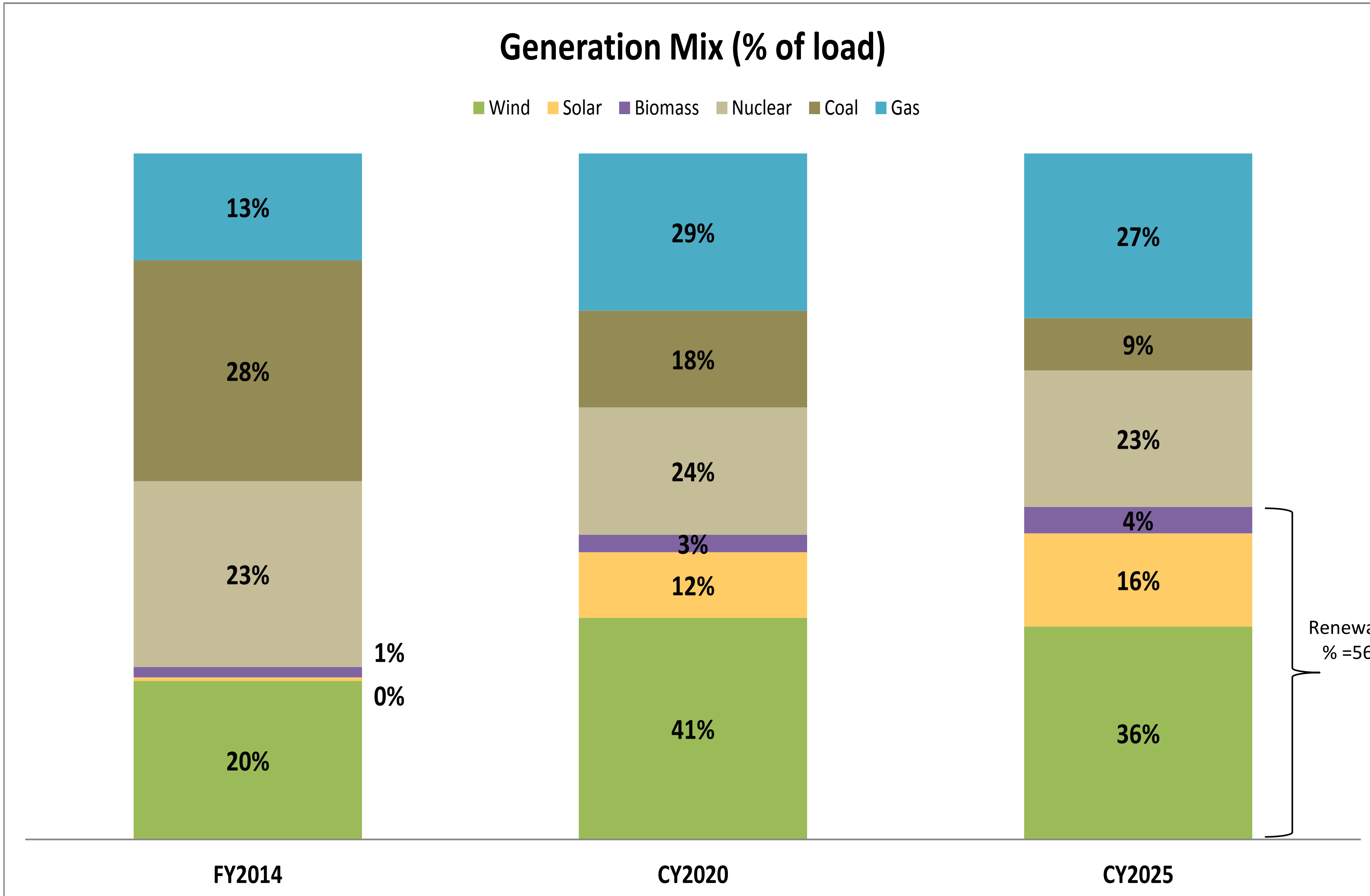
Energy Supply (% Mix) with
500+ 55% + 10 Li + FPP 2023 + 100 DR + 100 Local



Energy Supply with
500+ 55% + 10 Li + FPP Ramp + 100 DR + 100/200 Local



Energy Supply (% Mix) with
500+ 55% + 10 Li + FPP Ramp + 100 DR + 100 Local



500+ 55% + 10 Li + FPP 2023 + 100 DR + 100 Local

Year	Coal	Nuclear	Gas	Local Storage	Demand Response	Energy Efficiency	Biomass	Solar	Local Solar	Wind	% Renewables
2015	602	436	1,497				112		58.5[5]	1041	28%
2016								200[4]	25.4[6]	754[7]	51%
2017				1				150	5.4[6]	(91.5)[8]	54%
2018				1					5.4[6]	(34.5)[8]	53%
2019			(235)[3]	1					5.4[6]		53%
2020	(235)[1]			1	100 (cumulative)	700 (cumulative)		200[4]			57%
2021				1	20						56%
2022				1	20						55%
2023	(367)[2]			1	20					(165.6)[8]	56%
2024				1	20						52%
2025				2	20			200[4]			56%
Total Resources	**0**	**436**	**1262**	**10**	**200**	**700**	**112**	**750**	**100**	**1503**	

Note:

1) Equivalent MW reduction of Fayette Coal Plant to achieve 20% below 2005 CO_2 levels
2) Retirement of Fayette Coal Plant at the end of 2023
3) Net of Retirement of Decker Steam Units and addition of 500 MW Combined Cycle
4) New utility scale solar additions
5) Net of existing and new local solar additions
6) Total local solar additions including community solar
7) Net of committed wind and new additional wind
8) Expirations of existing wind contracts

500+55% + 10 Li + FPP Ramp + 100 DR + 100 Local

Year	Coal	Nuclear	Gas	Local Storage	Demand Response	Energy Efficiency	Biomass	Solar	Local Solar	Wind	% Renewables
2015	602	436	1,497				112		58.5[5]	1041	28%
2016								200[4]	25.4[6]	754[7]	51%
2017				1				150	5.4[6]	(91.5)[8]	54%
2018	(54)[1]			1					5.4[6]	(34.5)[8]	53%
2019	(54)[1]		(235)[3]	1					5.4[6]		53%
2020	(54)[1]			1	100 (cumulative)	700 (cumulative)		200[4]			57%
2021	(54)[1]			1	20						56%
2022	(54)[1]			1	20						55%
2023	(54)[1]			1	20					(165.6)[8]	56%
2024	(54)[1]			1	20						52%
2025	(224)[2]			2	20			200[4]			56%
Total Resources	**0**	**436**	**1262**	**10**	**200**	**700**	**112**	**750**	**100**	**1503**	

Note:

1) Equivalent MW reduction of FPP Coal Plant to achieve gradual reduction of CO_2 emissions each year to reduce overall CO2 reduction
2) Retirement of Fayette Coal Plant at the end of 2025
3) Net of Retirement of Decker Steam Units and addition of 500 MW Combined Cycle
4) New utility scale solar additions
5) Net of existing and new local solar additions
6) Total local solar additions including community solar
7) Net of committed wind and new additional wind
8) Expirations of existing wind contracts

500+ 55% + 10 Li + FPP 2023 + 100 DR + 200 Local

Year	Coal	Nuclear	Gas	Local Storage	Demand Response	Energy Efficiency	Biomass	Solar	Local Solar	Wind	% Renewables
2015	602	436	1,497				112		64.6[5]	1041	28%
2016								200[4]	32.5[6]	754[7]	50%
2017				1				150	32.5[6]	(91.5)[8]	53%
2018				1					22.5[6]	(34.5)[8]	52%
2019			(235)[3]	1					7.5[6]		52%
2020	(235)[1]			1	100 (cumulative)	700 (cumulative)		200[4]	7.5[6]		57%
2021				1	20				6.5[6]		55%
2022				1	20				6.5[6]		55%
2023	(367)[2]			1	20				6.5[6]	(165.6)[8]	55%
2024				1	20				6.5[6]		52%
2025				2	20			200[4]	6.5[6]		56%
Total Resources	**0**	**436**	**1262**	**10**	**200**	**700**	**112**	**750**	**200**	**1503**	

Note:

1) Equivalent MW reduction of Fayette Coal Plant to achieve 20% below 2005 CO_2 levels
2) Retirement of Fayette Coal Plant at the end of 2023
3) Net of Retirement of Decker Steam Units and addition of 500 MW Combined Cycle
4) New utility scale solar additions
5) Net of existing and new local solar additions
6) Total local solar additions including community solar
7) Net of committed wind and new additional wind
8) Expirations of existing wind contracts

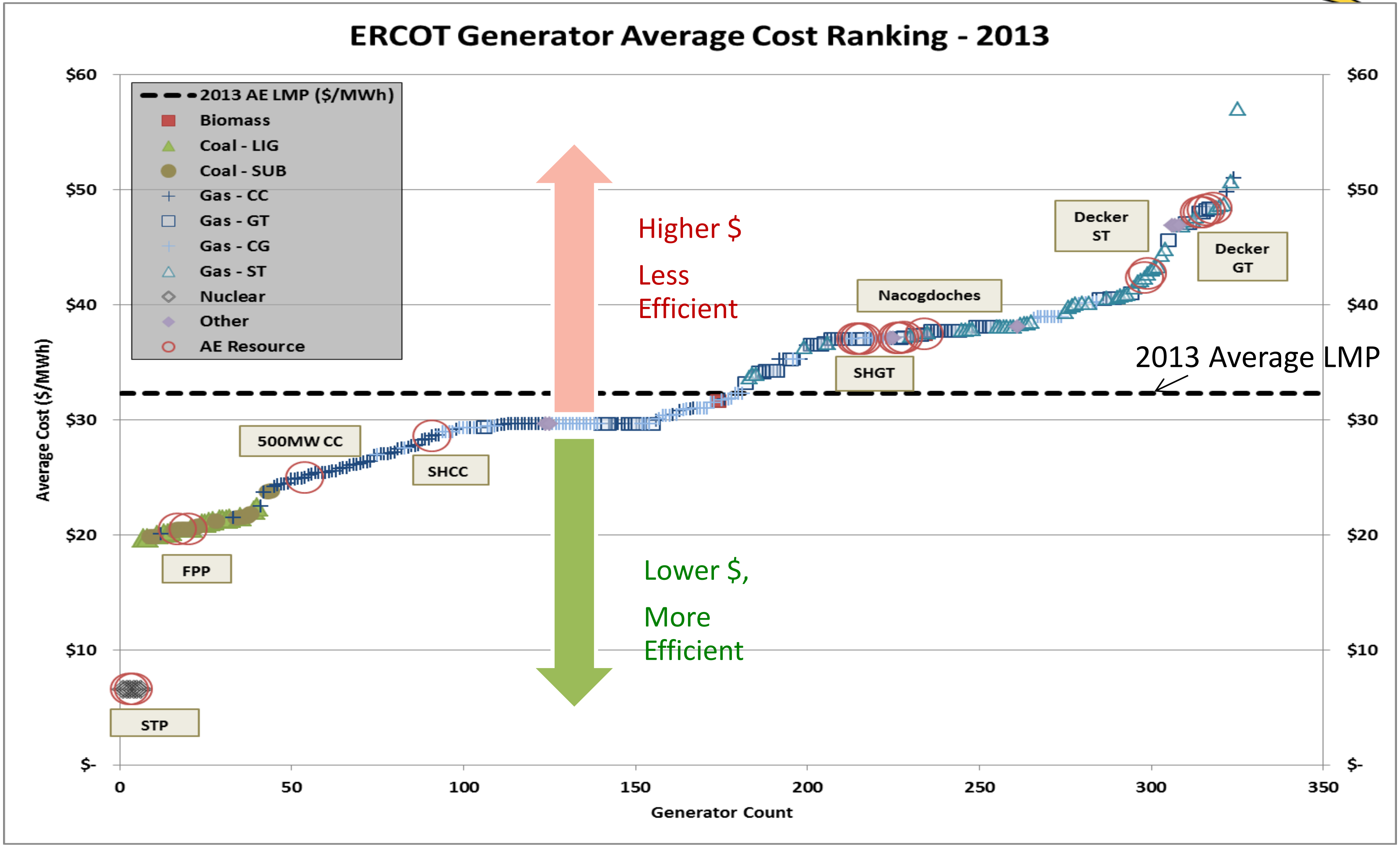
500+55% + 10 Li + FPP Ramp + 100 DR + 200 Local

Year	Coal	Nuclear	Gas	Local Storage	Demand Response	Energy Efficiency	Biomass	Solar	Local Solar	Wind	% Renewables
2015	602	436	1,497				112		64.6[5]	1041	28%
2016								200[4]	32.5[6]	754[7]	50%
2017				1				150	32.5[6]	(91.5)[8]	53%
2018	(54)[1]			1					22.5[6]	(34.5)[8]	52%
2019	(54)[1]		(235)[3]	1					7.5[6]		52%
2020	(54)[1]			1	100 (cumulative)	700 (cumulative)		200[4]	7.5[6]		57%
2021	(54)[1]			1	20				6.5[6]		55%
2022	(54)[1]			1	20				6.5[6]		55%
2023	(54)[1]			1	20				6.5[6]	(165.6)[8]	55%
2024	(54)[1]			1	20				6.5[6]		52%
2025	(224)[2]			2	20			200[4]	6.5[6]		56%
Total Resources	**0**	**436**	**1262**	**10**	**200**	**700**	**112**	**750**	**200**	**1503**	

Note:

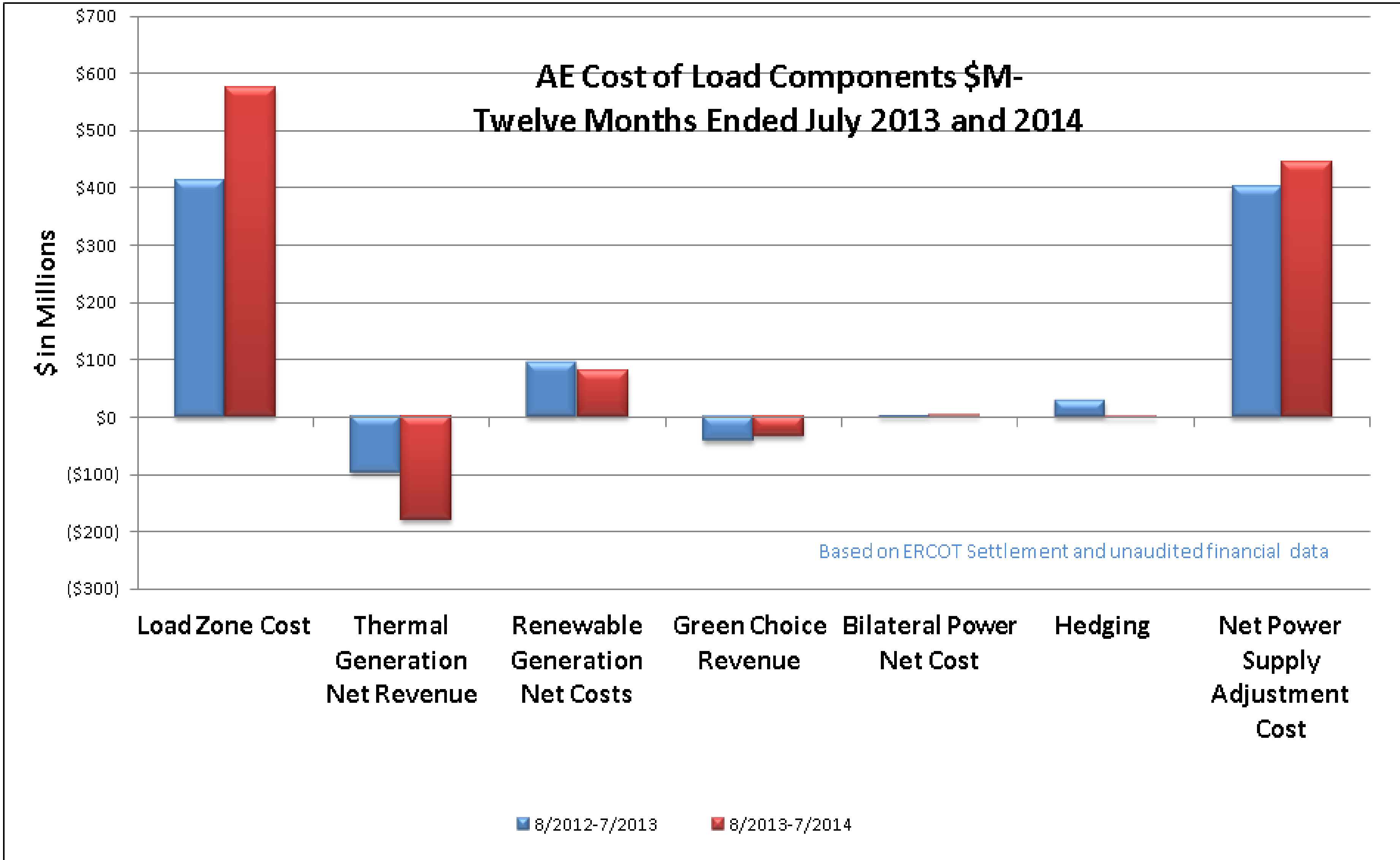
1) Equivalent MW reduction of FPP Coal Plant to achieve gradual reduction of CO_2 emissions each year to reduce overall CO2 reduction
2) Retirement of Fayette Coal Plant at the end of 2025
3) Net of Retirement of Decker Steam Units and addition of 500 MW Combined Cycle
4) New utility scale solar additions
5) Net of existing and new local solar additions
6) Total local solar additions including community solar
7) Net of committed wind and new additional wind
8) Expirations of existing wind contracts

New Resources displace Higher Cost Gas Resources



- Having units in the most efficient position within ERCOT keeps energy prices low for AE customers

PSA COST COMPONENTS

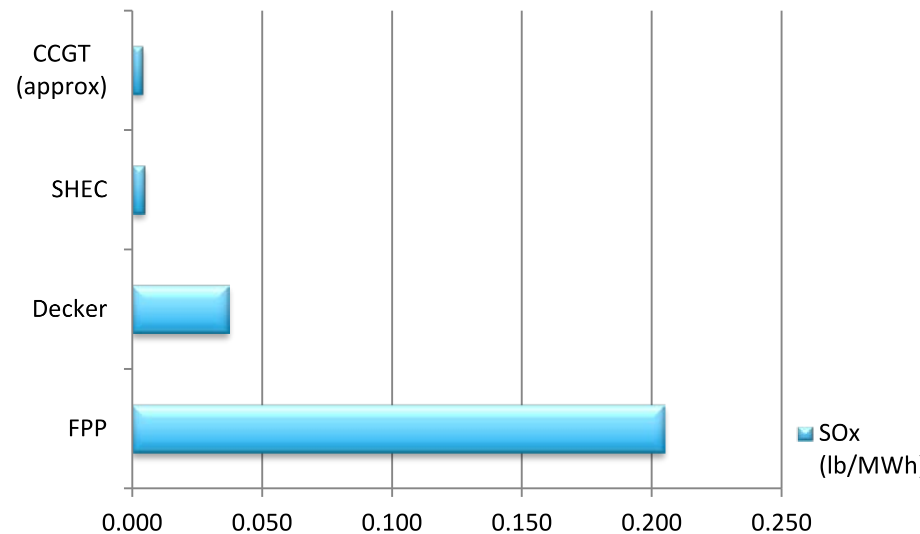


Comparing Emissions

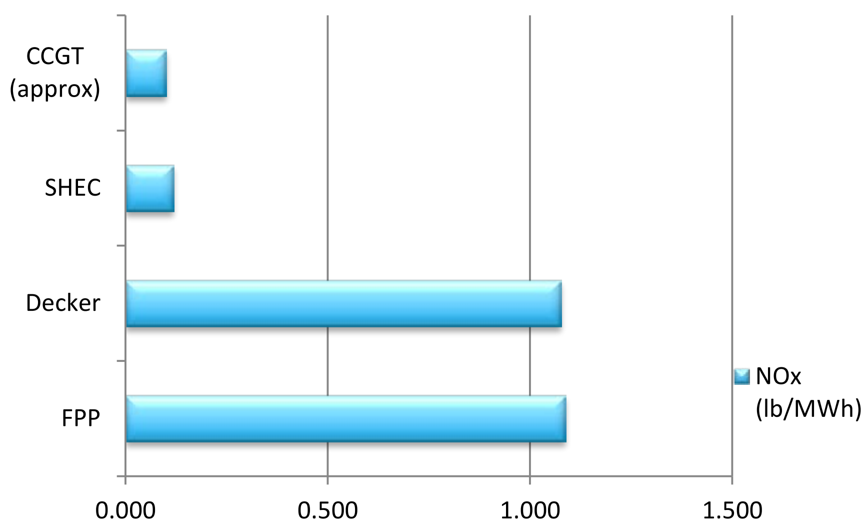
Migration to Latest Combined Cycle Technology results in (per MWhr):

- 53% more efficient gas to electricity conversion than Decker
- 60-90% less water use than Decker steam units
- 88% reduction in SO2 compared to Decker, 98% to FPP
- 92% reduction in NOx compared to Decker, 93% to FPP
- >50% reduction in CO2 over FPP

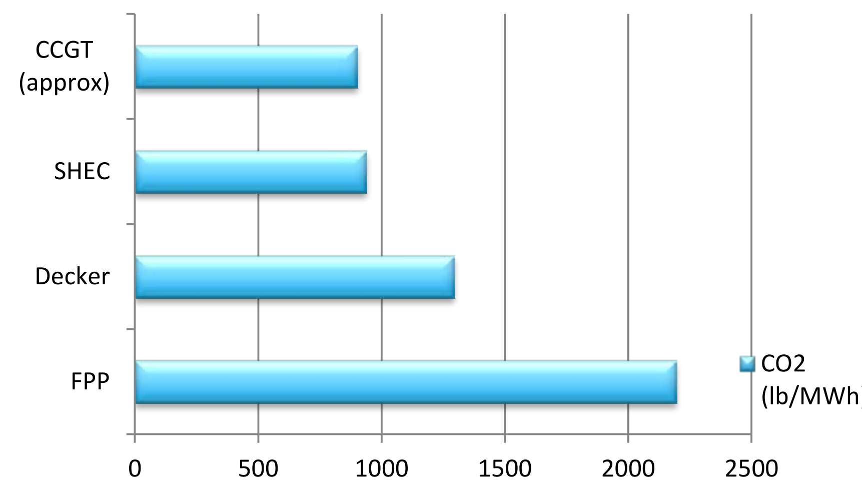
Sulfur Dioxide Emissions (lb/MWh)



Nitrous Oxides Emissions (lb/MWh)



Carbon Dioxide Emissions (lb/MWh)



Why is Proximity to Austin Important?

- The AE Load Zone is defined by Austin Energy's service area
- It is the metered demand of AE customer load
- Power generation within or in close proximity to Austin minimizes congestion risk and helps lower the price of energy in the load zone

WHY?

Basic Economics

Increased Local Supply vs. Local Demand Helps Lower Prices

AE Service Area

Scenario Descriptions

Scenario	Plan#	Long Description
1 - Current Strategy	SC1-1	Current goals - 35% Renewable and 800 MW DSM by 2020 - 200 MW Solar (100 MW Local, 50 MW Rooftop)
1 - Current Strategy	SC1-2	Current goals - 35% Renewable and 800 MW DSM by 2020 - 200 MW Solar (100 MW Local, 50 MW Rooftop) - Add 200 MW Sand Hill Expansion by 2020 - Add 40 MW Simple Cycle Gas Turbines by 2020 (2 x 40 MW)
2 - Do Nothing	SC2-1	Current System and Commitments and 800 MW DSM by 2020 - 200 MW Solar (100 MW Local, 50 MW Rooftop)
3 - Increase Ren/DSM	SC3-1	Increase goal to 40% Renewable by 2020
3 - Increase Ren/DSM	SC3-2	Increase goal to 40% Renewable by 2020 - Add 200 MW Sand Hill Expansion by 2020 - Add 40 MW Simple Cycle Gas Turbines by 2020 (2 x 40 MW)
3 - Increase Ren/DSM	SC3-3	Increase goal to 40% Renewable by 2020 - Increase DSM Goal to 1,000 MW 2020
3 - Increase Ren/DSM	SC3-4	Increase goal to 40% Renewable by 2020 - Increase DSM Goal to 1,000 MW by 2020 - Add 200 MW Sand Hill Expansion by 2020 - Add 40 MW Simple Cycle Gas Turbines by 2020 (2 x 40 MW)
4 - Increase Ren/DSM More	SC4-1	Increase goal to 50% Renewable by 2025
4 - Increase Ren/DSM More	SC4-2	Increase goal to 50% Renewable by 2025 - Add 200 MW Sand Hill Expansion by 2020 - Add 40 MW Simple Cycle Gas Turbines by 2020 (2 x 40 MW)
4 - Increase Ren/DSM More	SC4-3	Increase goal to 50% Renewable by 2025 - Increase DSM Goal to 1,200 MW 2020
4 - Increase Ren/DSM More	SC4-4	Increase goal to 50% Renewable by 2025 - Increase DSM Goal to 1,200 MW by 2020 - Add 200 MW Sand Hill Expansion by 2020 - Add 40 MW Simple Cycle Gas Turbines by 2020 (2 x 40 MW)

Scenario Descriptions Contd..

Scenario	Plan#	Long Description
5 - Carbon Free	SC5-1	Carbon Free (Current goals - 35% Renewable and 800 MW DSM by 2020) - 200 MW Solar (100 MW Local, 50 MW Rooftop) - Retire Decker Plant December 2017 - Retire FPP December 2025 - Retire Sand Hill Plant December 2025
5 - Carbon Free	SC5-2	Carbon Free (Increase Goal to 40% Renewable by 2020) - 200 MW Solar (100 MW Local, 50 MW Rooftop) - Retire Decker Plant December 2017 - Retire FPP December 2025 - Retire Sand Hill Plant December 2025
5 - Carbon Free	SC5-3	Carbon Free (Increase Goal to 50% Renewable by 2025) - 200 MW Solar (100 MW Local, 50 MW Rooftop) - Retire Decker Plant December 2017 - Retire FPP December 2025 - Retire Sand Hill Plant December 2025
5 - Carbon Free	Res. 157	Carbon Free (Increase Goal to 65% Renewable by 2025) - 600 MW Utility Scale Solar by 2016 - 200 MW Solar (100 MW Local, 50 MW Rooftop) - Retire Decker Plant December 2017 - Retire FPP December 2025 - Retire Sand Hill Plant December 2030 - 200 MW Storage (50 MW Local Battery, 150 MW CAES)
5 - LOW Carbon	Res. 157 + SHExp	Carbon Free (Increase Goal to 65% Renewable by 2025) - 600 MW Utility Scale Solar by 2016 - 200 MW Solar (100 MW Local, 50 MW Rooftop) - Retire Decker Plant December 2017 - Retire FPP December 2025 - Retire Sand Hill Plant December 2030 - 200 MW Storage (50 MW Local Battery, 150 MW CAES) - 200 MW Sand Hill CC Expansion
5 - LOW Carbon	Res. 157 + 300MW_H	Carbon Free (Increase Goal to 65% Renewable by 2025) - 600 MW Utility Scale Solar by 2016 - 200 MW Solar (100 MW Local, 50 MW Rooftop) - Retire Decker Plant December 2017 - Retire FPP December 2025 - Retire Sand Hill Plant December 2030 - 200 MW Storage (50 MW Local Battery, 150 MW CAES) - 300 MW Combined Cycle at Decker

Scenario Descriptions Contd..

Scenario	Plan#	Long Description
5 - Carbon Free	Res. 157 + 158	Carbon Free (Increase Goal to 65% Renewable by 2025) - Increase DSM Goal to 1,200 MW by 2024 - 600 MW Utility Scale Solar by 2016 - 200 MW Solar (100 MW Local, 50 MW Rooftop) - Retire Decker Plant December 2017 - Retire FPP December 2025 - Retire Sand Hill Plant December 2030 - 200 MW Storage (50 MW Local Battery, 150 MW CAES)
5 - Carbon Free	SC5-4	Carbon Free (Increase Goal to 40% Renewable by 2020) - 200 MW Solar (100 MW Local, 50 MW Rooftop) - Increase DSM Goal to 1,000 MW by 2020 - Retire Decker Plant December 2017 - Retire FPP December 2025 - Retire Sand Hill Plant December 2025
5 - Carbon Free	SC5-5	Carbon Free (Increase Goal to 50% Renewable by 2025) - 200 MW Solar (100 MW Local, 50 MW Rooftop) - Increase DSM Goal to 1,200 MW by 2025 - Retire Decker Plant December 2017 - Retire FPP December 2025 - Retire Sand Hill Plant December 2025
5 - Carbon Free	SC5-6	Carbon Free (Current goals - 35% Renewable and 800 MW DSM by 2020) - 200 MW Solar (100 MW Local, 50 MW Rooftop) - Retire Decker Plant December 2017 - Retire FPP December 2025 - Retire Sand Hill Plant December 2025 - Replace Retire Plant Energy with Renewable
6 - Retire FPP	SC6-1	Current goals - 35% Renewable and 800 MW DSM by 2020 - 200 MW Solar (100 MW Local, 50 MW Rooftop) - Retire FPP December 2025
6 - Retire FPP	SC6-2	Current goals - 35% Renewable and 800 MW DSM by 2020 - 200 MW Solar (100 MW Local, 50 MW Rooftop) - Retire FPP December 2025 - Replace FPP Energy with Renewable
6 - Retire FPP	SC6-3	Current goals - 35% Renewable and 800 MW DSM by 2020 - 200 MW Solar (100 MW Local, 50 MW Rooftop) - Retire FPP December 2025 - Replace FPP Energy with Renewable - Add 780 MW Combined Cycle by 2020
6 - Retire FPP	SC6-4	Current goals - 35% Renewable and 800 MW DSM by 2020 - 200 MW Solar (100 MW Local, 50 MW Rooftop) - Retire FPP December 2025 - Replace FPP Energy with Renewable - Add 317 MW Compressed Air Energy Storage (CAES) by 2020

Scenario Descriptions Contd..

Scenario	Plan#	Long Description
7 - Retire Decker Plant	SC7-1	Current goals - 35% Renewable and 800 MW DSM by 2020 - 200 MW Solar (100 MW Local, 50 MW Rooftop) - Retire Decker Plant December 2017
7 - Retire Decker Plant	SC7-2	Current goals - 35% Renewable and 800 MW DSM by 2020 - 200 MW Solar (100 MW Local, 50 MW Rooftop) - Retire Decker Plant December 2017 - Replace Decker Plant Energy with Renewable
7 - Retire Decker Plant	SC7-3	Current goals - 35% Renewable and 800 MW DSM by 2020 - 200 MW Solar (100 MW Local, 50 MW Rooftop) - Retire Decker Plant December 2017 - Replace Decker Plant Energy with Renewable - Add 780 MW Combined Cycle by 2018 - Add 160 MW Simple Cycle Gas Turbines by 2018 (4 x 40 MW)
7 - Retire Decker Plant	SC7-4	Current goals - 35% Renewable and 800 MW DSM by 2020 - 200 MW Solar (100 MW Local, 50 MW Rooftop) - Retire Decker Plant December 2017 - Replace Decker Plant Energy with Renewable - Add 317 MW Compressed Air Energy Storage (CAES) by 2020
8 - Retire FPP and Decker Plant	SC8-1	Current goals - 35% Renewable and 800 MW DSM by 2020 - 200 MW Solar (100 MW Local, 50 MW Rooftop) - Retire FPP December 2025 and Decker Plant December 2017
8 - Retire FPP and Decker Plant	SC8-2	Current goals - 35% Renewable and 800 MW DSM by 2020 - 200 MW Solar (100 MW Local, 50 MW Rooftop) - Retire FPP December 2025 and Decker Plant December 2017 - Replace Retired Energy with Renewable
8 - Retire FPP and Decker Plant	SC8-3	Current goals - 35% Renewable and 800 MW DSM by 2020 - 200 MW Solar (100 MW Local, 50 MW Rooftop) - Retire FPP December 2025 and Decker Plant December 2017 - Replace Retired Energy with Renewable - Add 780 MW Combined Cycle by 2018 - Add 160 MW Simple Cycle Gas Turbines by 2018 (4 x 40 MW)
8 - Retire FPP and Decker Plant	500+Plan	Current goals - 35% Renewable and 800 MW DSM by 2020 - 500 MW Solar Additional Utility Solar PV - 100 MW Local, 50 MW Rooftop - Retire FPP December 2025 and Decker Steam Plant December 2017 - Increase Total Renewable Goal to 50% by 2025 - Add 500 MW Combined Cycle by 2018 at Decker Site
9 - Retire FPP and Decker Steam Plant	55%+10Li+FPPRamp+100DR	Current goals - 35% Renewable and 800 MW DSM by 2020 - 500 MW Solar Additional Utility Solar PV - 100 MW Local, 50 MW Rooftop - Retire FPP December 2025 and Decker Steam Plant December 2017 - Begin FPP Ramp Down in 2018 - Increase Total Renewable Goal to 50% by 2025 - Add 500 MW Combined Cycle by 2018 at Decker Site - Add 10 MW of Local Storage + 20 MW Thermal Storage - Add 100 MW Demand Response (DR) by 2025
9 - Retire FPP and Decker Steam Plant	55%+10Li+FPP23+100DR	Current goals - 35% Renewable and 800 MW DSM by 2020 - 500 MW Solar Additional Utility Solar PV - 100 MW Local, 50 MW Rooftop - Retire FPP December 2025 and Decker Steam Plant December 2017 - Increase Total Renewable Goal to 50% by 2025 - Add 500 MW Combined Cycle by 2018 at Decker Site - Add 10 MW of Local Storage + 20 MW Thermal Storage - Add 100 MW Demand Response (DR) by 2025

Appendix 4.

Southern Wind Energy Association

P.O. Box 1842, Knoxville, TN 37901

October 31, 2015

Ms. Melanie Verzwyvelt
Louisiana Public Service Commission
Galvez Building, 12th Floor
602 North Fifth Street
Baton Rouge, LA 70821-9154

RE: LPSC Docket No. I-33014. Transmission Analysis for Disputed Items for Entergy Louisiana, LLC and Entergy Gulf States Louisiana LLC Final Integrated Resource Plan ("IRP"),

Dear Ms. Verzwyvelt,

The Southern Wind Energy Association (SWEA) has conducted a transmission analysis for the Louisiana Public Service Commission. This analysis is in response to the Docket No. I-33014, for the Entergy Louisiana, LLC and Entergy Gulf States Louisiana LLC Final Integrated Resource Plan (IRP). In the Final IRP, wind energy transmission costs were provided; however, no clear methodology nor data was provided.

SWEA conducted its own transmission analysis based on hourly load data for the Entergy System and locational marginal pricing data (LMP) for fourteen different wind farms sited throughout the Southwest Power Pool (SPP). Hourly load data from 2007-2012 for the Entergy System are publicly available via the Federal Energy Regulatory Commission form 714 data. Those data were compared against various wind farm nodes within the SPP footprint, the SPP/Entergy System interface, and the two nodes used in the Final IRP, EES.EGILD and EES.ESLILD from September 1, 2014 to August 31, 2015. LMP data were not available for EES.EGILD and EES.ESLILD from March 1 to May 26; average week prior and average week after LMPs were used in place of the absences. All results were averaged and load-weighted. SWEA's LMP differential results for the Spearville, Centennial and Keenan wind farms are virtually the same as the Final IRP results, see Figure 1 below.

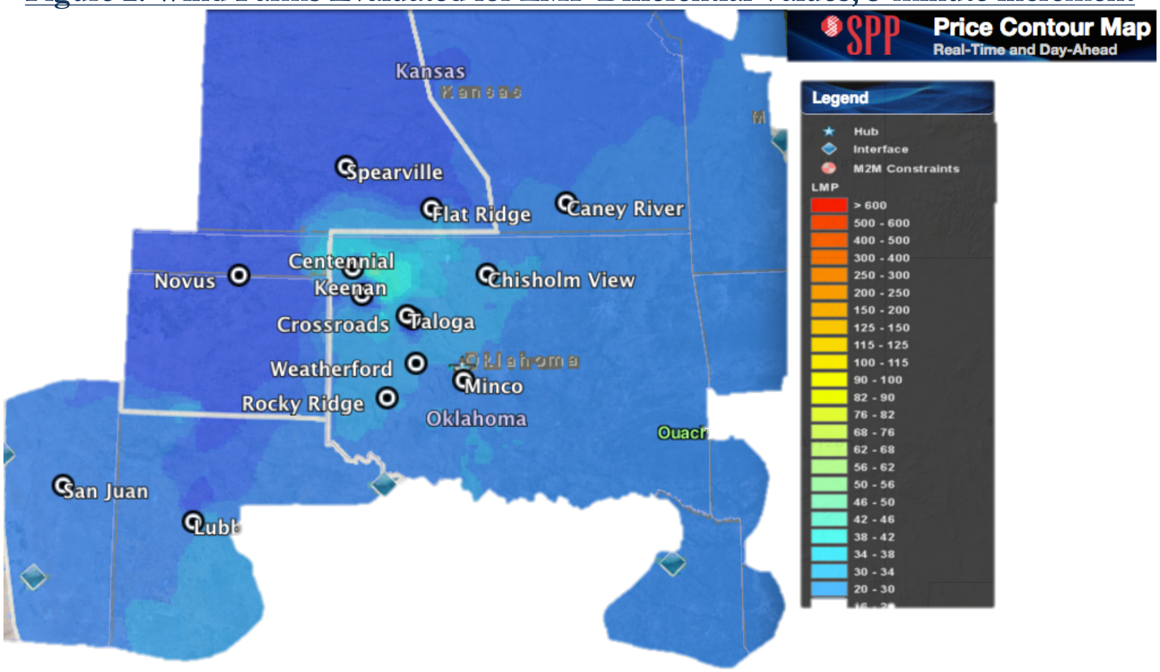
Figure 1. LMP Differential Result Comparison

Wind Farm	Final IRP Results	SWEA Results
Spearville	\$12.92	\$12.55
Centennial	\$17.07	\$16.59
Keenan	\$13.84	\$14.84
Average	\$14.60	\$14.66

The minor differences between the Final IRP and SWEA's LMP differential results is likely due do the different timeframes of the data analyzed.

The three wind farms evaluated for the Final IRP (Spearville, Centennial and Keenan) are in some of the worst congested areas within SPP. As such, these three wind farms do not represent a fair analysis for LMP differentials. SWEA evaluated the three wind farms, in addition to eleven other wind farms within SPP. Figure 2 shows the fourteen total wind farms plotted against a recent LMP contour map from SPP.

Figure 2. Wind Farms Evaluated for LMP Differential Values, 5-minute increment



As mentioned previously, SWEA evaluated the individual and average LMP differentials compared against EES.EGILD and EES.ESLILD, but also the SPP/Entergy interface. Contractually, wind energy could be delivered to the SPP/Entergy interface and then Entergy would obtain network service via MISO. Energy delivery to the interface, as opposed to EES.EGILD and EES.ESLILD, is a significantly lower-cost option, see Figure 3.

Figure 3. Various LMP Differentials Based on Wind Farm Site and Energy Delivery Point ($/MWh)

	EES.EGILD	EES.ELILD	Avg. ESS	SPP-EES INTERFACE
Spearville	$13.16	$11.93	$12.55	$4.51
Centennial	$17.21	$15.98	$16.59	$8.56
Kennan	$15.45	$14.22	$14.84	$6.80
Caney River	$8.32	$7.09	$7.71	-$0.33
Weatherford	$5.56	$4.34	$4.95	-$3.08
Chisholm View	$7.32	$6.10	$6.71	-$1.33
Minco	$6.02	$4.79	$5.40	-$2.63
Taloga	$4.64	$3.41	$4.03	-$4.01
Crossroads	$11.91	$10.69	$11.30	$3.26
Novus	$13.17	$11.95	$12.56	$4.52
San Juan	$3.47	$2.24	$2.85	-$5.18
Lubbock	$4.97	$3.74	$4.36	-$3.68
Rocky Ridge	$6.51	$5.29	$5.90	-$2.13
Flatridge	$8.26	$7.03	$7.64	-$0.39
Averages	$9.00	$7.77	$8.38	$0.35

As can be seen in Figure 3, the three wind farms selected for LMP differential analysis (Spearville, Centennial and Keenan) are some of the highest cost wind projects evaluated. When taking other projects into consideration, the cost estimate used in the Final IRP of $14.60/MWh is roughly 74% higher than the average LMP differential for delivery into the average between EES.EGILD and EES.ESLILD. If Spearville, Centennial and Keenan are removed from analysis, the Final IRP LMP differential price is 119% higher than other wind farm sites.

As a secondary delivery option, Figure 3 shows energy delivery to the SPP-EES (Entergy) Interface. Most wind farms evaluated show a negative LMP differential, indicating a source of revenue. The average LMP differential for the fourteen wind projects is just $0.35/MWh, indicating that the Final IRP LMP differential price to be over 4,000% too high. If the three wind farms evaluated in the Final IRP are excluded, the average LMP differential price for the eleven projects evaluated is -$1.32/MWh. This figure is in line with what the Georgia Power Company (GPC) found in its analysis of various wind farm proposals submitted via its Request for Information (RFI) earlier this year, see the transmission cost results of the GPC RFI in Figure 4.

Figure 4. Example Average Oklahoma and Kansas Transmission Delivery Charges to the Southern Balancing Authority

	Example Oklahoma Wind Generator		Example Kansas Wind Generator	
	Congestion	Losses	Congestion	Losses
MISO	$1.44	$1.66	$3.76	$1.93
SPP	$ (1.21)	$ (0.10)	$6.82	$1.88

Source: GPC RFI February 2015[1]

Figure 4, adapted from the GPC RFI, corroborates SWEA's results, that example wind generators within SPP represent very low LMP differentials for energy imported eastward.

The Final IRP LMP differential analysis is biased against wind energy and used unrealistically congested wind projects for evaluation. This unrealistic transmission analysis was coupled with excessively high levelized cost of energy (LCOE) wind energy prices in the Final IRP. This analysis and SWEA's previous analyses show that wind energy can provide great value to Louisiana ratepayers. Please consider requiring the Final IRP models to be re-run with up-to-date information about wind energy.

Respectfully submitted:

Simon Mahan
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Southern Wind Energy Association
P.O. Box 1842
Knoxville, TN 37901
Telephone: 337-303-3723
simon@cleanenergy.org

[1] Georgia Power Company (February 27, 2015). Report Summarizing the Responses Received and Georgia Power's Filings Regarding Opportunities for Additional Wind Generation Resources [http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=157251]