RESOLUTION

NO. R-26-360

CITY HALL: Septembers, 2026

BY: COUNCILMEMBERS MCCARRON, MORRELL, GREEN, HARRIS, HUGHES AND KING

RESOLUTION AND ORDER ESTABLISHING RULEMAKING TO CONSIDER REVISING THE INTEGRATED RESOURCE PLAN RULES WITH RESPECT TO DISTRIBUTED ENERGY RESOURCES

DOCKET NO. UD-26-01

WHEREAS, pursuant to the Home Rule Charter of the City of New Orleans, the Council of the City of New Orleans ("Council") is the governmental body with the power of supervision, regulation, and control over public utilities providing service within the City of New Orleans; and

WHEREAS, pursuant to its powers of supervision, regulation and control over public utilities, the Council is responsible for fixing and changing rates and charges of public utilities, making all necessary rules and regulations governing the terms and conditions of service, applications for the fixing and changing of rates and charges of public utilities, and all other regulatory proceedings; and

WHEREAS, Entergy New Orleans, LLC ("ENO") is a public utility providing electric service to all of New Orleans; and

WHEREAS, in July of 2017, the Council adopted Resolution R-17-332, adopting new IRP rules, which were later amended in R-17-429 to add a statement of purpose to the rules and clarify what actions the Council might take in response to the filing. The rules adopted in R-17-429, the "Electric Utility Integrated Resource Plan Rules of the Council of the City of New Orleans" ("IRP Rules") are the currently effective IRP Rules for New Orleans; and

WHEREAS, on December 18, 2025, the Council adopted Resolution No. R-25-629 accepting and approving ENO's 2024 IRP Final Report and its Action Plan, and granting parties 90 days to comment on certain recommendations made by the Advisors for future IRP proceedings; and

WHEREAS, in their Advisors' Report on the 2024 IRP Final Report, the Advisors noted that other ongoing Council dockets regarding distributed energy resources ("DERs") are likely to implement changes to Council policies around DERs that will impact the IRP analyses, and that technological and market changes regarding DERs have occurred since the Council's current IRP Rules were adopted.[1] The Advisors identified several areas where the current IRP Rules need to be revised to better reflect these changes, and recommended that the Council consider opening a proceeding to evaluate revising the IRP Rules with respect to how DERs are included in both the DSM Potential Study and the IRP analyses to reflect these recent developments;[2] and

WHEREAS, on March 18, 2026, ENO submitted the *Comments of Entergy New Orleans, LLC's on Advisor Recommendations for Future IRP* ("ENO Comments"). The ENO Comments were generally supportive of the Advisors' recommendations to update the IRP Rules to account for developments in the types and characteristics of DERs since the most recent IRP Rules were adopted in 2017, and set forth proposed edits to the definition of "Distributed Energy Resources" under the IRP Rules, as well as an explanation of the different types of distributed resources that are either currently deployed in New Orleans or planned for deployment in the future, and how Entergy's System Planning & Operations group treats each of the distributed resources in developing portfolios through the IRP analyses; and

[1] Advisors' Report at 37.
[2] Advisors' Report at 37-38.

WHEREAS, no other comments were filed regarding the Advisors' recommendations; and;

WHEREAS, on May 21, 2026, the Council in Resolution No. R-26-220 established Docket No. UD-26-01 and adopted a procedural schedule to evaluate revising the IRP Rules with respect to how DERs are included in the Demand Side Management ("DSM") Potential Study and the IRP analyses; and

WHEREAS, the purpose of Docket No. UD-26-01 is to ensure that the Council's IRP Rules appropriately recognize the changing nature of electric resources available to serve New Orleans customers, including customer-sited generation, energy storage, demand response, distributed generation, and other technologies capable of modifying or supplying electric demand; and

WHEREAS, on June 18, 2026, the Alliance for Affordable Energy ("AAE") filed its comments asserting that DERs should be modeled as distinct technologies rather than lumped together as an aggregate resource and that the Council should consider requiring non-wire alternatives ("NWA") analysis to reveal the full benefits of DERs to the distribution grid; and

WHEREAS, on June 18, 2026, ENO submitted its comments and specific revisions to the IRP Rules with respect to its application of DERs explaining that the existing definition of DERs is focused primarily on customer-owned, behind-the-meter resources, while DERs currently available or potentially available in New Orleans may be owned or leased by retail customers, third parties, or the utility and may be interconnected behind or in front of a customer meter; and

WHEREAS, ENO proposed revising the definition of DERs to include generation or energy storage facilities owned or leased by retail customers, third parties, or the utility located on the customer side of the meter, primarily for the use and consumption of energy by the retail

customer, interconnected to the distribution grid, and capable of delivering energy to the distribution grid; and

WHEREAS, on July 16, 2026, Gulf States Renewable Energy Industries Association ("GSREIA"), filed its *Petition for Leave to Intervene Out of Time and Initial Comments on Proposed Changes to the IRP Rules* asserting DERs should be evaluated as full planning resources, on a technology-neutral basis, in both the DSM Potential Study and the IRP analysis; and

WHEREAS, on July 17, 2026, ENO submitted its comments regarding the Advisors' proposed changes to the IRP Rules: (i) expressing concern that to attempt to incorporate holistic transmission and distribution planning and the optimized selection of DERs in portfolios into the IRP process would present numerous issues; (ii) ENO can still model distribution-connected resources and include them in optimization, assuming they are given the relevant cost and performance inputs; and (iii) ENO cannot anticipate and mitigate the risk of outages on the distribution or transmission grid in the IRP planning process; and

WHEREAS, on July 17, 2026, AAE filed comments supporting the integration of distribution and transmission planning into the IRP process, recommending the mitigation of outage risk among the IRP's objectives, and objecting to ENO's proposed revision to the definition of "Distributed Energy Resources" under the IRP Rules inasmuch as it includes non-renewable generation;

WHEREAS, on July 31, 2026, the Advisors filed reply comments to ENO and GSREIA comments filed on July 17, 2026; and

WHEREAS, the Advisors agreed with ENO's proposal that manual portfolios can be used to evaluate specific types and amounts of DERs as a method of portfolio development, and acknowledged that further detailed grid-related analyses are needed to provide the capability to

integrate distribution and transmission planning into the IRP process, and to evaluate the extent to which the reliability of the distribution system can be improved; and

WHEREAS, the Advisors recommended that an additional scope to the DSM Potential Study be included in the Council's IRP Initiating Resolution to study the potential of DERs as an additional component beyond the energy and demand response potential that has been evaluated in previous studies.[3] The Advisors are in general agreement with GSREIA's recommendation that DERs should be evaluated as full planning resources, on a technology-neutral basis, in both the DSM Potential Study and the IRP analysis, but that there should be further discussions with ENO regarding its implementation in the IRP process; and

WHEREAS, in its July 31, 2026 reply comments, ENO disagrees with AAE regarding the proposed definition of DERs in the redlined IRP rules, and believes that it should accurately reflect the full range of DERs available to, and active in, the ENO market, citing numerous ENO commercial and industrial customers that have installed fossil-fueled generation behind their meters and are available to participate in demand response ("DR") programs; and

WHEREAS, ENO requests that the Council (i) initiate a rulemaking to investigate the implications of direct registration of its jurisdictional customers through Aggregators of Retail Customers ("ARCs") and to protect New Orleans customers from the ongoing risks of direct registration of DR programs by ARCs, and (ii) consider adoption of a Market Valued Demand Response tariff to facilitate registration of ENO customers; and

WHEREAS, ENO agrees it would be instructive and helpful to undertake a distribution system "non-wires alternative" study as part of the 2027 IRP to identify a number of possible DER

[3] As discussed in its previous comments, ENO plans to include in the scope of the 2027 DSM potential study an assessment of potential DERs as standalone grid-connected devices in addition to the DSM and DR potential normally studied.

projects and evaluate the costs and benefits such that they could be included in the Aurora capacity expansion and portfolio optimization used as part of the IRP process; that such study can be executed in parallel with the DSM Potential Study; and ENO requests that the Council account for the required time at the beginning of the 2027 IRP procedural schedule; and

WHEREAS, on August 3, 2026, the Hearing Officer, Jeffrey Gulin, certified the record and submitted it to the Council for final consideration; and

WHEREAS, the Council has considered the comments and recommendations submitted in Docket No. UD-26-0I, including the comments of ENO, AAE, GSREIA, and the comments and recommendations of the Council's Advisors, and has determined that the attached amendments adopted herein represent a reasonable and balanced approach that serves the public interest; and

WHEREAS, the Council will consider in separate proceedings the Company's requests to initiate a rulemaking to investigate the implications of direct registration of its jurisdictional customers through ARCs, and to adopt a Market Valued Demand Response tariff to facilitate registration of ENO customers; and

WHEREAS, the Council finds that it is in the public interest to balance the need for immediate improvements to the IRP Rules with the recognition that certain more sophisticated DER, transmission, distribution, locational, avoided cost, and storage analyses may require additional modeling capabilities and should therefore be implemented through subsequent IRP proceedings and initiating resolutions; **NOW THEREFORE**

BE IT RESOLVED BY THE COUNCIL OF THE CITY OF NEW ORLEANS, That the Council hereby adopts the following revisions and clarifications to the IRP Rules originally adopted by Resolution No. R-l 7-429 contained in Attachment A (redlined version) and Attachment B (clean version).

BE IT FURTHER RESOLVED BY THE COUNCIL OF THE CITY OF NEW ORLEANS, That the Council Utilities Regulatory Office is directed to work with the Council Advisors to revise the *Council of the City of New Orleans Utility Regulatory Manual* to reflect the amendments to the Integrated Resource Plan rules herein.

THE FOREGOING RESOLUTION WAS READ IN FULL, THE ROLL WAS CALLED ON THE ADOPTION THEREOF, AND RESULTED AS FOLLOWS:

YEAS: **Green, Harris, Hughes, King, McCarron, Morrell, Willard - 7**

NAYS: 0

ABSENT: **0**

AND THE RESOLUTION WAS ADOPTED.

THE FOREGOING IS CERTIFIED
TO BE A TRUE AND CORRECT COPY

Aisha Collier

CLERK OF COUNCIL

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Attachment A
To Resolution R-26-___

REDLINE OF ELECTRIC UTILITY INTEGRATED RESOURCE PLAN RULES
of the
Council of the City of New Orleans

ATTACHMENT B
TO RESOLUTION R-17- 429

ELECTRIC UTILITY INTEGRATED RESOURCE PLAN RULES
of the
Council of the City of New Orleans

ELECTRIC UTILITY INTEGRATED RESOURCE PLAN RULES
of **the**
Council of the City of New Orleans

These IRP Rules are intended to inform and empower effective Council and utility decision-making, while augmenting utility resource planning and enhancing public awareness of and input into the utility's energy choices. It is the Council's desire that a comprehensive IRP conducted in accordance with these IRP Rules provide a full picture of all reasonably available resource options in light of current and expected market conditions and technology trends, and generate an informed understanding of the economic, reliability, and risk evaluation of utility resource planning as well as the associated social and environmental impacts. Further, the Council wishes to encourage and enforce a transparent process that allows all interested constituents and stakeholders to participate and that fosters the development of a complete administrative record upon which informed Council decision-making can occur.

Section 1. Overview

A. These rules supersede the "Electric Utility Integrated Resource Plan Rules of the City of New Orleans" adopted by Council Resolution R-17-332. The purpose of these rules is to establish an open and transparent process by which all electric utilities, subject to the Council of the City of New Orleans (Council) regulatory jurisdiction, develop and file Integrated Resource Plans (IRP).

B. Each IRP triennial planning cycle shall be commenced with an Initiating Resolution of the Council which outlines the IRP process and timeline; Intervenor and public participation, policy objectives for consideration in the IRP, and other matters as deemed necessary by the Council.

C. Each Utility IRP shall include a matrix of these rules, the corresponding section of the IRP responsive to that rule, and a brief description of how the Utility complied with the rules.

D. Each Utility IRP is intended to serve as a general resource planning tool to the Utility and the Council, rather than a forum for the approval of the acquisition, implementation, or deactivation of any supply-side or demand-side resource.

E. To the extent there is non-compliance with these rules, after the showing of cause, consistent with the provisions of Chapter 158 Article ~~II~~III, Division ~~8~~II, Sec. 158-~~512~~26 of the Code of the City of New Orleans and all applicable due process requirements, the Council may impose penalties for non-compliance with these rules.

Section 2. Definitions

A. ln these rules, unless otherwise specified, the following te1ms shall have the meaning defined in this Section:

1. "Advanced Metering Infrastructure" (AMI) - refers to meters and their underlying technology, including communication and data handling systems, that record

customer usage for time intervals of one hour or less, and can transmit information to the Utility without the need for a human meter reader. The meter allows for two-way flow of information and can notify the Utility of a power outage, and facilitate Demand Response programs.

2. "Advisors" - refers to the legal and technical consultants retained by the Council to assist it in its regulatory responsibilities.

3. "CURO" - refers to the Council Utilities Regulatory Office.

4. "Demand Side Management" (DSM) - refers to energy efficiency and Demand Response programs administered by the Utility. It includes the planning, implementation, and monitoring activities designed to modify energy usage patterns.

5. "Demand Response" (DR) - refers to a DSM program that seeks to modify customer loads to reduce or shift loads from hours with high electricity costs (peak hours) or reliability constraints to other hours. Demand Response programs include, but are not limited to: (a) those ~~. Demand Response~~ load-control programs that are dispatchable or controlled by the Utility, such as interruptible loads and direct load control of energy storage and end-use loads, including appliances, and(b) those ~~Demand Response~~load-control programs that are not controlled by the Utility, but rather involve a customer response during peak periods, such as critical peak pricing, time-of-use (TOU) rates, and any other rate design that sends market signals to customers to encourage ~~efficient electricity consumption~~reducing or shifting loads during peak hours. Demand Response also includes any other programs that shift loads from higher- to lower-energy cost times that may become available through the deployment of AMI or other technologies.

6. "Demand-Side Resources" – refers to those resources which impact the energy and peak demand served by the Utility, including DSM and the Distributed Energy Resource capacity which impacts utility customers' peak and energy usage.

7. "Distributed Energy Resources" (DERs) - refers to generation or energy storage facilities owned or leased by retail customers, third parties, or the Utility that are ~~located on the customer side of the meter, that are primarily for the use and consumption of energy by the retail customer, and that are~~ interconnected to the Utility distribution grid and capable of delivering energy to the distribution grid. Distributed Energy Resources may include renewable/non-renewable generators, combined heat and power, ~~and~~ energy storage technology (including electric vehicles), and any other technology that may similarly serve or dispatch energy ~~from the customer side of the meter~~to the distribution grid.

~~6.~~8. "'Distributed Resources' – refers to both Demand Side Management and Distributed Energy Resources

~~7.~~9. "Initiating Resolution" - refers to a resolution of the Council which initiates the triennial IRP planning cycle, enumerates related Council policies, and establishes the procedural schedule and such other matters as the Council deems appropriate~~;~~, including ~~and~~the process to be utilized by the Utility, stakeholders and Interested Parties throughout the IRP development process.

~~8.~~10. "Integrated Resource Planning" - is an open, transparent planning process through which all relevant supply-side and demand-side resources (including all ~~DSM~~ distributed resources), and the factors influencing choice among them, while integrating transmission and distribution planning into the overall resource planning process, are investigated for the optimal set of resources to meet current and future electric service needs at the lowest total cost to customers and the Utility, in a manner consistent with the long-run public interest, given the expected combination of costs, benefits, reliability, risks and uncertainty.

~~9.~~11. "Interested Person" - refers to an individual or entity who desires to receive information and notices of public meetings as part of the IRP process and who is not a party to the proceeding. CURO shall maintain a list of Interested Persons and forward to them copies of all filings, issuances, and notices occurring in the proceeding. This may be accomplished through the Council's electronic docketing system once that docketing system develops the necessary capabilities.

~~10.~~12. "Intervenor" - refers to persons who have intervened in the case pursuant to the New Orleans, Louisiana Code of Ordinances, Chapter 158, Article III.

13. "Load Forecast"- refers to a forecast of electricity demand (MW) and energy (MWh) for the Utility that takes into account currently implemented demand-side management and distributed energy resources, ~~and customer-owned DERs,~~ but does not include any anticipated or incremental demand-side resources.

~~11.~~14. Load Modifying Resource – refers to a Midcontinent Independent System Operator (MISO) market participant asset used during capacity emergencies to maintain grid reliability by reducing electricity consumption/demand or by dispatching backup generation when called upon (as with certain DERs or solar stations in standby availability).

~~12.~~15. "New Orleans Technical Reference Manual" (NOTRM) - refers to a common reference document for estimating energy and peak demand reduction ("deemed savings") resulting from the installation of DSM measures promoted by utility-administered programs in New Orleans. This document is a compilation of deemed savings values previously approved by the Council and the Advisors for use in estimating savings for DSM measures. The NOTRM is updated periodically as required by the Council through a collaborative process involving the Council, the Advisors, the Utility, the Third Party Administrator and the third party Evaluation, Measurement and Verification ("EM&V") contractor, and other parties as needed. The data and methodologies in this document are to be used by program planners, administrators, implementers and evaluators for forecasting, reporting and evaluating energy and demand savings,

costs, and other metrics from ~~DSM~~ demand-side measures installed in New Orleans.

~~13.~~16. "Planning Period" - refers to the number of projected years over which the existing resources and various potential resource options are evaluated in the IRP process.

~~14.~~17. "Planning Scenario"- refers to a distinct definition of a market outlook for the IRP Planning Period consisting of key parameters which are not controlled by the Utility or the Council. Several Planning Scenarios are constructed to identify the plausible futures of the IRP Planning Period. Various Planning Strategies are then evaluated relative to each of the defined Planning Scenarios.

~~15.~~18. "Planning Strategy" - refers to the defining of distinct resource constraints, regulatory policies, or business decisions over which the Council, the Utility, or Intervenors have control. For example, a Planning Strategy can be traditional utility planning, intervenors defining resource inputs, or a Planning Strategy reflecting Council policies. Each distinct Planning Strategy is evaluated relative to each Planning Scenario, resulting in an optimized Resource Portfolio for each Planning Scenario/Planning Strategy combination.

~~16.~~19. "Resource Portfolio"- refers to prescribed combinations of supply-side resources, demand-side resources, and transmission and distribution investment for comparative evaluation in IRP modeling and reporting. Modeling of the intersection of a Planning Scenario and a Planning Strategy results in an optimized Resource Portfolio with a defined cost and associated risk. For example, if four Planning Scenarios and two separate Planning Strategies are defined, there would be eight Resource Portfolios.

~~17.~~20. "Regional Transmission Organization" (RTO) - refers to the Midcontinent Independent System Operator (MISO) or any successor RTO of which the Utility is a participating member.

~~18.~~**21.** "Stakeholder" - refers to any person potentially impacted by the outcome of the IRP, whether that person formally intervenes in the proceeding or not.

22. "Stakeholder Process" - refers to the meaningful engagement of stakeholders throughout the IRP process, specifically addressed in the Initiating Resolution commencing an IRP cycle.

~~19.~~23. "Supply-Side Resources" – refers to those resources which provide the load and capability, in terms of kW and/or kWh, to meet the Utility's current and projected resource needs and load requirements during the Planning Period. Supply-Side Resources include Utility-owned resources and purchased power agreements (PPAs), third-party PPAs, Load Modifying Resources, and DER capacity used to meet Utility resource needs and load requirements.

~~20.~~24. "Utility"- refers to any electric utility subject to the Council's regulatory jurisdiction.

Section 3. Objectives

A. The Utility shall state and support specific objectives to be accomplished in the IRP planning process, which include but are not limited to the following:

1. optimize the integration of Ssupply-S~~s~~ide resources and D~~d~~emand-S~~s~~ide resources, while taking into account transmission and distribution planning, to provide New Orleans ratepayers with reliable electricity at the lowest practicable cost given an acceptable level of risk;

2. maintain the Utility's financial integrity;

3. anticipate and mitigate risks associated with fuel and market prices, environmental compliance costs, and other economic factors;

4. support the resiliency and sustainability of the Utility's systems in New Orleans;

5. comply with local, state and federal regulatory requirements and regulatory requirements and known policies (including such policies identified in the Initiating Resolution) established by the Council;

6. evaluate the appropriateness of incorporating advances in technology, including, but not limited to, renewable energy, energy storage, and DERs, among others;

7. achieve a range of acceptable risk in the trade-off between cost and risk; and

8. maintain transparency and engagement with stakeholders throughout the IRP process by conducting technical conferences and providing for stakeholder feedback regarding the Planning Scenarios, Planning Strategies, input parameters, and assumptions.

B. In the IRP Report, the Utility shall discuss its efforts to achieve each of the objectives identified in Section 3A and any additional specific objectives identified in the Initiating Resolution.

Section 4. **Load Forecast**

A. The Utility shall develop a reference case Load Forecast and at least two alternative Load Forecasts applicable to the Planning Period which are consistent with the Planning Scenarios identified in Section 7C. The following data shall be supplied in support of each Load Forecast:

I. The Utility's forecast of demand and energy usage by customer class for the Planning Period;

2. A detailed discussion of the forecasting methodology and a list of independent variables and their reference sources that were utilized in the development of the Load Forecast, including assumptions and econometrically evaluated estimates. The details of the Load Forecast should identify the incremental energy and demand impacts of projected Utility-sponsored DSM program additions and ~~customer-owned~~ DER~~.s~~ capacity which impact Utility kW and

kWhs, as well as ~~and~~ the then existing DER capacity and Utility-sponsored DSM programs. The load forecast should reflect as decrements to load, the organic adoption of customer-controlled DERs, such as net metered solar;

3. Forecasts of the independent variables for the Planning Period, including their probability distributions and statistical significance;

4. The expected value of the Load Forecast as well as the probability distributions (uncertainty ranges) around the expected value of the Load Forecast; and

5. A discussion of the extent to which line losses have been incorporated in the Load Forecast.

~~5.~~6. Specific data supporting the individual decrements to the Load Forecast attributed to DSM programs, DER capacity, and behind-the-meter/ net-energy-metering solar, recognizing the availability of modeling input variables.

B. The Utility shall construct composite customer hourly load profiles based on the forecasted demand and energy usage by customer class and relevant AMI and load research data, including the factors which determine future load levels and shape.

C. Concurrent with the presentation of the Load Forecasts to the Advisors, CURO, and stakeholders, the Utility shall provide historical demand and energy data for the five (5) years immediately preceding the Planning Period. At a minimum, the following data shall be provided:

1. monthly energy consumption for the Utility in total and for each customer class;

2. monthly coincident peak[1] demand for the Utility and estimates of the monthly coincident peak demand for each customer class;[2] and

3. estimates of the monthly peak demand for each customer class;[3]

D. The data and discussions developed pursuant to Section 4A and Section 4B, and Section 4C shall be provided as an attachment to the IRP report and summarized in the IRP report.

[1] For the purposes of Section 4C, "monthly coincident peak" refers to the peak coincident with the RTO monthly peak.
[2] To the extent ENO has or attains the technical capability to collect load data on a customer class level, it shall collect and report the historic data in lieu of the customer class level estimates.
[3] To the extent ENO has or attains the technical capability to collect load data on a customer class level, it shall collect and report the historic data in lieu of the customer class level estimates.

E. The Utility shall also provide a list of any known co-generation resources, community solar, and DERs ~~larger than 300 kW~~ existing on the Utility's system, including resources maintained by the City of New Orleans for city/parish purposes, (e.g. Sewerage and Water Board, Orleans Levee District, or by independent agencies or entities such as universities, etc.).

Section 5. Resource Options

A. Identification of resource options. The Utility shall identify and evaluate all existing Ssupply-Sside and Ddemand-Sside resources and identify a variety of potential Ssupply-Sside and Ddemand-Sside resources which can be reasonably expected to meet the Utility's projected resource needs during the Planning Period.

1. Existing Ssupply-Sside resources. For existing Ssupply-Sside resources, including Distributed Resources, the Utility should incorporate all fixed and variable costs necessary to continue to utilize the resource as part of a Resource Portfolio. Costs shall include the costs of any anticipated renewal and replacement projects as well as the cost of regulatory mandated current and future emission controls.

   a. The Utility shall identify important changes to the Utility's existing Supply-Side resource mix that occurred since the last IRP including large capital projects, resource procurements, LMRs, DERs, changes in fuel types, and actual or expected operational changes regardless of cause.

   b. Data supplied as part of the Utility's IRP filing should include a list of the Utility's existing Ssupply-Sside Rresources, including Distributed Resources, with the list to include: the resource name, fuel type, capacity rating at time of summer and winter peak, and typical operating role (e.g. base, intermediate, peaking).

2. For existing demand-side resources, including Distributed Resources, the Utility should account for load reductions attributable to the then-existing Ddemand-Sside Rresources in each year of the Planning Period. Each existing Ddemand-Sside Rresource will be identified as either a specific energy efficiency/DR program ~~or DR program~~ with an individual program lifetime, a DER resource, or other Demand-Side Resource (e.g. NEM), ~~and~~ with the estimated energy and demand reductions applicable to the Planning Period associated with each existing Demand-Side Resource.~~, or as a then-existing Utility owned or Utility-managed distributed generation resource with energy and demand impacts that are estimated for applicable years of the Planning Period.~~ Data supplied as part of the Utility's IRP filing should include:

   a. Details of projected kWh/kW reductions from existing DSM programs based on quantifiable results and other credible support derived from Energy Smart New Orleans, or any successor program, using verified data available to the Utility from prior DSM program implementation years.

   ~~a.~~b. Details of projected kWh/kW reductions from existing DER and other Demand-Side Resources (e.g. NEM) based on supporting documentation.

~~b.~~c. A list categorizing the Utility's existing Ddemand-Sside Rresources including anticipated capacity at time of summer and winter peak.

3. With respect to potential Ssupply-Sside Rresources, including Distributed Resources, the Utility shall consider: Utility-owned and purchased power resources; third-party PPAs, conventional and new generating technologies including technologies expected to become commercially viable during the Planning Period; technologies utilizing renewable fuels; energy storage technologies; cogeneration resources; and Distributed Energy Resources; among others.

   a. The Utility should incorporate any known Council policy goals (including such policy goals identified in the Initiating Resolution) with respect to resource acquisition, including, but not limited to, renewable resources, energy storage technologies, and DERs, including relevant data from current dockets applicable to the Planning Period.

   b. Data supplied as part of the Utility's IRP filing should include: a description of each potential Ssupply-Sside Rresource including a technology description, operating characteristics, capital cost or demand charge, fixed operation and maintenance costs, variable charges, variable operation and maintenance costs, earliest date available to provide supply, expected life or contractual term of resource, and fuel type with reference to fuel forecast.

4. Potential Ddemand-Sside resources. With respect to potential Ddemand-Sside Rresources, the Utility should consider and identify all cost-effective and Council-approved Ddemand-Sside Rresources through the development of a DSM Ppotential Sstudy and other analyses of Demand-Side Resources accepted by Council. The cost-effectiveness of Demand-Side Resources can be determined by the Total Resource Cost ("TRC") and Ratepayer Impact Measure ("RIM") benefit-cost analyses ("BCA"), or other BCA tests, such as the National Standards Practice Manual[4], as specified under the Council's Policy Objectives in the IRP Initiating Resolution. All DSM measures with a Total Resource Cost Test[5] value of 1.0 or greater shall be considered cost-effective for DSM measure screening purposes.

   a. The DSM Ppotential Sstudy shall include, but not be limited to: identification of eligible measures, measure life expectancies, baseline standards, load reduction profiles, incremental capacity and energy savings, measure and program cost assumptions, participant adoption rates, market development, and avoided energy and capacity costs for DSM measure and program screening purposes. The scope of the DSM potential study should include an assessment of potential DERs as standalone grid-connected devices in addition to the DSM and DR potential normally studied. DERs should be disaggregated by type for the purposes of modeling and evaluation.

[4] The National Standards Practice Manual for Benefit Cost Analysis of Distributed Energy Resources, 2026 edition, and its compendium, Benefit-Cost Analysis Case Studies, are publications of National Association of State Energy Officials (NASEO), developed by NASEO's National Energy Screening Project (NESP). The DERs addressed in this Manual include: Energy efficiency (EE), Demand response (DR), Distributed generation (DG), Distributed storage (DS), and Electrification-related DERs.

[5] California Standard Practice Manual: Economic Analysis of Demand-Side Programs and projects, State of California Governor's Office of Planning and Research July 2002.

b. The principal reference document for the DSM potential study, DERs, and other Demand-Side Resources shall be the New Orleans Technical Reference Manual.

c. In the development of the DSM Ppotential Sstudy, ~~all four California Standard Practice Tests (i.e. TRC, PACT, RJM and PCT)~~ BCA tests addressed herein and in the Initiating Resolution will be calculated for the DSM measures and programs considered.

d. The Utility should incorporate any known Council policy goals or targets (including such policy goals or targets identified in the Initiating Resolution) with respect to Ddemand-Sside Rresources.

e. The cost-effective DR programs should include consideration of those programs enabled by the deployment of Advanced Meter Infrastructure, including both direct load control and DR pricing programs for both Residential and Commercial customer classes.

f. Data supplied as part of the Utility's IRP filing should include: a description of each potential Ddemand-Sside rResource considered, including a description of the DER resource or DSM program; expected penetration levels by planning year; hourly load reduction profiles for each ~~DSM program~~potential Demand-Side Resource utilized in the IRP process; and results of appropriate cost-benefit analyses and acceptance tests, as part of the planning assumptions utilized within the IRP planning process.

g. The Council will make a decision and announce it in the Initiating Resolution whether it will procure an independent consultant to perform a DSM Potential Study. In the event the Council does not procure an independent contractor, ENO shall provide a DSM Potential Study.[6]

B. Through the Stakeholder Process, the Utility shall strive to develop a position agreed to by the Utility, the Advisors, and a majority of the Intervenors regarding the potential Ssupply-Sside and potential Ddemand-Sside Rresources and their associated defining characteristics (e.g., capital cost, operating and maintenance costs, emissions, potential DSM supply curve, DER supply-side and demand-side capacity, etc.).

1. To the extent such a consensus can be achieved among the Utility, the Advisors, and a majority of the Intervenors,[7] the resulting collection of potential Ssupply-Sside and Ddemand-Sside Rresources and their associated defining characteristics will be utilized in the reference Planning Strategy developed pursuant to Section 7D.

2. To the extent such a consensus cannot be achieved, the Utility shall model, in coordination with the requirements in Section 7D, two distinct Planning Strategies: a reference Planning Strategy and a stakeholder Planning Strategy. The reference Planning Strategy will be based on the Utility's assessment of the collection of potential Ssupply-Sside and Ddemand-Sside Rresources and their associated defining characteristics. The stakeholder Planning Strategy will be determined by a majority of the Intervenors and modeled by the Utility based on inputs provided to the Utility describing the collection of potential Ssupply-Sside and

[6] This provision does not preclude any party from entering their own DSM potential study into the docket

[7] An Intervenor not consenting to the majority position and thus not joining in the consensus retains the ability to oppose the consensus position before the Council and assert its own position.

Ddemand-Sside Rresources and their associated defining characteristics.[8] To maintain consistency in the modeling process, the Advisors will work with the Intervenors and the Utility to: ensure that input that is provided for the stakeholder Planning Strategy can be accommodated within the framework of the existing models and software.[9]

Section 6. Transmission and Distribution

A. The Utility shall explain how the Utility's current transmission and distribution systems, and any planned transmission and distribution system expansions (including regional transmission system expansion planned by the RTO in which the Utility participates) ~~and the Utility's distribution system~~ are integrated into the overall resource planning process to optimize the Utility's resource portfolios and provide New Orleans ratepayers with reliable electricity at the lowest practicable cost.

B. Models developed for the integrated resource planning process should incorporate the planned configuration of the Utility's transmission and distribution systems, and the interconnected RTO during the Planning Period. A distribution system "non-wires alternative" study should be considered as part of the IRP process to identify possible DER projects and evaluate the costs and benefits that could be included in the portfolio optimization; such study can be executed in parallel with the DSM Potential Study

C. To the extent major changes in the operation or planning of the transmission system and/or distribution system (including changes to accommodate the expansion of DERs) are contemplated in the Planning Period, the Utility should describe the anticipated changes and provide an assessment of the cost and benefits to the Utility and its customers.

D. To the extent that new resource additions are selected by the Utility for a Resource Portfolio based on reliability needs rather than as a result of the optimized development of a Resource Portfolio, the Utility shall identify reasonable transmission and/or distribution solutions that can be employed to either reduce the size, delay, or eliminate the need for the new reliability-driven resource additions, and provide economic analyses demonstrating why the new reliability-driven resource addition was selected in lieu of the transmission and/or distribution solutions identified.

E. It is the Council's intent that, as part of the IRP, the Utility shall evaluate the extent to which reliability of the distribution system can be improved through the strategic location and timing of DERs or other resources additions identified as part of the IRP planning process. The Utility should provide an analysis, discussion, and quantification of the costs and benefits as part of the evaluation. To the extent the Utility does not currently have the capability to meet this requirement, the utility shall demonstrate progress toward accomplishing this requirement until such time as it acquires the capability.

Section 7. Integrated Resource Plan Analyses

[8] An Intervenor not consenting to the majority position retains the ability to oppose the consensus position before the Council and assert its own position.

[9] The Utility shall have no obligation to incorporate element(s) of the stakeholder Planning Strategy that cannot be accommodated by the Utility's modeling capabilities.

A. The integrated resource planning process should include modeling of specific parameters and their relationships consistent with market fundamentals, and *as* appropriate for long-term Integrated Resource Portfolio planning. This overall modeling approach is an accepted analytic approach used in resource planning considering the range of both Ssupply-Sside and Ddemand-Sside Resource options as well as uncertainty surrounding market pricing. To represent and account for the different characteristics of alternative types of resource options, mathematical methods, such as a linear programming formulation, shcould be used to optimize resource decisions.[10]

B. The optimization process shall be constrained to mitigate the over-reliance on forecasted revenues from external capacity market sales and external energy market sales driving the selection of resources.

C. The Utility shall develop three to four Planning Scenarios that incorporate different economic and environmental circumstances and national and regional regulatory and legislative policies.

D. The Planning Scenarios should include a Rreference Planning Scenario that represents the Utility's point of view on the most likely future circumstances and policies, as well as two alternative Planning Scenarios that account for alternative circumstances and policies.

1. In the development of the Planning Scenarios, the Utility should seek to develop a position agreed to by the Utility, Advisors, and a majority of Intervenors[11] regarding the assumptions surrounding each of the Planning Scenarios. To the extent such a consensus is not reasonably attainable regarding the Planning Scenarios, the Utility shall model a fourth Planning Scenario which is based upon input agreed to by a majority of the Intervenors.[12]

2. For each IRP Planning Scenario, data supplied as part of the Utility's IRP filing should include:

   a. a fuel price forecast for each fuel considered for utilization in any existing or potential supply-side resource;

   b. an hourly market price forecast for energy (e.g. locational marginal prices);

   c. an annual capacity price forecast for both a short-term capacity purchase *(e.g.* bilateral contract or Planning Resource Credit) and a long-term capacity purchase (e.g. long-run marginal cost of a new replacement gas combustion turbine); and

   d. forecasts of price for any other price-related components that are defined by the Planning Scenario (e.g. CO2 price forecast, etc.).

[10] Linear programming is a mathematical method or model of optimizing Jinem functions or relationships within constraints to achieve the lowest costs.

[11] An Intervenor not consenting to the majority position and thus not joining in the consensus retains the ability to oppose the consensus position before the Council and assert its own position.

[12] An Intervenor not consenting to the majority position and thus not joining in the consensus retains the ability to oppose the consensus position before the Council and assert its own position.

E. Distinct from the Planning Scenarios, the Utility shall identify two to four Planning Strategies which constrain the optimization process to achieve particular goals, regulatory policies and/or business decisions over which the Council, the Utility, or Sstakeholders have control.

1. The Utility shall develop a Planning Strategy that allows the optimization process to identify the lowest cost option for meeting the needs identified in the IRP process.

2. The Utility shall develop a Rreference Planning Strategy agreed to by the Utility, Advisors, and a majority of the intervenors.[13] To the extent such a consensus cannot be reasonably achieved, the Rreference Planning Strategy shall reflect the Utility's point of view on resource input parameters and constraints, and the Utility shall model a separate Sstakeholder Planning Strategy based upon input determined by a majority of the Intervenors.[14] 30

[13] An Intervenor not consenting to the majority position and thus not joining in the consensus retains the ability to oppose the consensus position before the Council and asse11 its own position.

[14] An Intervenor not consenting to the majority position and thus not joining in the consensus retains the ability to oppose the consensus position before the Council 1mcl assert its own position.

3. As necessary, the Utility shall develop alternate Planning Strategies to reflect known utility regulatory policy goals of the Council (including such policy goals or targets identified in the Initiating Resolution) as established no later than 30 days prior to the date the Planning Strategy inputs must be finalized.

F. Prior to the development of optimized Resource Portfolios, the parameters developed for the Planning Scenarios and Planning Strategies shall be set, considered finalized, and not subject for alteration during the remainder of the IRP planning cycle. The IRP Report shall describe the parameters of each Planning Scenario and each Planning Strategy, including all artificial constraints utilized in the optimization modeling.

G. Resource Portfolios shall be developed through optimization utilizing the Utility's modeling software. The Utility shall identify the least-cost Resource Portfolio for each Planning Scenario and Planning Strategy combination, based on total cost. Resource Portfolios shall consist of optimized combinations of Ssupply-Sside and Ddemand-Sside Rresources, including potential DSM programs selected from the DSM Potential Study and application of DER capacity, while recognizing constraints including transmission and distribution planning. Manual portfolios can be used to evaluate specific types and amounts of DERs as a method of portfolio development.

H. The Utility shall provide (i) a discussion and presentation of results for each Planning Scenario/Planning Strategy combination, (ii) the annual total demand-related costs, energy-related costs, and total supply costs associated with each least-cost Resource Portfolio identified under each Planning Scenario/Planning Strategy combination, (iii) a load and capability table indicating the total load requirements and identifying all Ssupply-Sside and Ddemand-Sside Rresources included in the Resource Portfolio, (iv) ~~(including identifying~~ the annual impacts of existing Ddemand-Sside Rresources on the total load requirements, and the annual impacts of potential DSM and DERs in Resource Portfolio Optimization~~)~~, and (v) a description of the potential Ssupply-Sside and Ddemand-Sside Rresources that are ~~planned~~projected for the Planning Period and, if applicable, their principal rationale for selection (i.e., supply peak demand, supply non-peak demand, ~~or~~ operational and policy constraints, achieve more economical production of energy, etc.).

1. Data supplied as part of the Utility's IRP filing shall include a cumulative present worth summary of the results as well as the annual estimates of Supply-Side and Demand-Side Resource costs that result in the cumulative present worth to enable the Council to understand the timing of costs and savings of each least-cost Resource Portfolio.

I. The IRP report's discussion and presentation of results for each Resource Portfolio should identify key characteristics of that Resource Portfolio and significant factors that drive the ultimate cost of that Resource Portfolio such that the Council may understand which factors could ultimately and significantly affect the preference of a Resource Portfolio by the Council.

J. The Utility will develop and include a scorecard template or set of quantitative and qualitative metrics to assist the Council in assessing the IRP based on the Resource Portfolios. The scorecard should rank the Rresource Pportfolios by how well each portfolio achieves each

metric. Such metrics should include but not necessarily be limited to: cost[15]; impact on the Utility's revenue requirements; risk; flexibility of resource options[16]; DER policy and those resource portfolios that include DERs, reasonably quantifiable environmental impacts (such as national average emissions for the technologies chosen, amount of groundwater consumed, etc.); consistency with established, published city policies, such as the City's sustainability plan; and macroeconomic impacts in New Orleans.

Section 8. Risk Analyses

A. The Utility shall develop a cost/risk analysis which balances quantifiable costs with quantifiable risks of the identified least-cost Resource Portfolios. The risk assessment must be presented in the IRP to allow the Council to comprehend the robustness of each Resource Portfolio across the cost/risk range of possible Resource Portfolios.

1. In quantifying Resource Portfolio costs/risks, the IRP shall assess any social and environmental effects of the Resource Portfolios to the extent that; l) those effects can be quantified and have been modeled for a Resource Portfolio, including the applicable Planning Period years and ranges of uncertainty surrounding each externality cost, and 2) each quantified cost must be clearly identified by the portion which relates to the Utility's revenue requirements or cost of providing service to the Utility's customers under the Resource Portfolio.

2. It is the Council's intent that, as part of the IRP, a risk assessment be conducted to evaluate both the expected outcome of potential costs as well as the distribution and potential range and associated probabilities of outcomes. To the extent the Utility believes the risk assessment described herein is beyond the current modeling capabilities of the Utility or that the risk assessment cannot be accomplished within the procedural schedule set forth in the Initiating Resolution, the Utility shall so inform the Council and meet with the Intervenors and Advisors to agree upon an alternative form of risk analysis to recommend to the Council.

   a. The risk assessment shall include the expected cost per MWh of the Resource Portfolios in selected future years, along with the range of annual average costs foreseen for the 10th and 90th percentiles of simulated possible outcomes.

   b. The supporting methodology shall be included, such as the iterations or simulations performed for the selected years, in which the possible outcomes are drawn from distributions that describe market expectations and volatility as of the current filing date.

Section 9. IRP Process Requirements

A. At a minimum, the IRP process shall include, but not be limited to, the following elements:

[15] The cost metric should include the cost of quantified externalities as well as Utility costs resulting from the lRP optimization.

[16] The flexibility metric includes response to load swings and quick start.

1. The opportunity for Intervenors to participate in the concurrent development of inputs and assumptions for the major components of the IRP (including the DSM Potential Study and those resource portfolios that include DERs) in collaboration with the Utility within the confines of the IRP timeline and procedural schedule.

2. At least four technical meetings attended by the parties in the Docket focused on major IRP components that include the Utility, intervenors, CURO, and the Advisors with structured comment deadlines so that meeting participants have the opportunity to present inputs and assumptions and provide comments, and attempt to reach consensus while remaining mindful of the procedural schedule established in the Initiating Resolution.

3. At least 3 public engagement technical conferences advertised through multiple media channels at a minimum of 30 days prior to the public technical conference.

   a. A public education and kickoff meeting that explains the following: the purpose of the IRP and the corresponding process; the IRP timeline as delineated in the Council's Initiating Resolution with respect to major process deadlines; the inputs and assumptions that are considered in the IRP process and summarized in the report; and ways in which public can remain informed throughout the IRP cycle (e.g., online information resources that provide status updates, portal through which customers can submit questions or concerns to the Utility);

   b. A public presentation of the IRP; and

   c. A public hearing opportunity after presentation of the IRP report to give the public the opportunity to provide comment on the record.

4. CURO shall schedule, provide notice of, and conduct the public technical conferences. In addition to a live presentation, all public technical conferences should also be broadcast via the Council's website and archived for later viewing.

Section 10. Submission and Public Presentation of IRP

A The Utility shall make its IRP available for public review subject to the provisions of the Council Resolution initiating the current IRP planning cycle and referenced in Section 1B.

B. The Utility shall file its IRP with the Council consistent with and subject to the provisions of the Council Resolution initiating the current IRP planning cycle referenced in Section 1B.

C. The IRP report should discuss the stakeholders' engagement throughout the IRP process; the access to data inputs and specific modeling results by all parties; the consensus reached regarding all Ddemand-Sside and Ssupply-Sside Rresource inputs and assumptions, including application/integration of DERs; specific descriptions of unresolved issues regarding inputs, assumptions, or methodology; the formulation of the stakeholder Planning Scenario and/or Sstakeholder Planning Strategy as needed; and recommendations to improve the transparency and efficiency of the IRP process for prospective IRP cycles.

D. The IRP shall include an action plan and timeline discussing any steps or actions the Utility may propose to take as a result of the IRP, understanding that the Council's acceptance of the filing of the Utility's IRP would not operate as approval of any such proposed steps or actions.

E. Provided the IRP fulfills the requirements contained herein and was developed in compliance with the procedural schedule established for the triennial IRP cycle, the Council shall accept the Utility's IRP as filed in compliance with the Council's substantive and procedural requirements. Failure of the utility to substantially comply with the provisions of these Rules may result in summary rejection of the Utility's IRP. Such rejection may be without prejudice to the refiling of the IRP once the utility has corrected the deficiencies. Further, after consideration of all of the evidence entered into the record, the Council may approve the accepted Utility IRP, approve it subject to stated conditions, approve it with modifications, approve it in part and reject it in part, reject it in its entirety, or choose to terminate the proceeding without either approving or rejecting the accepted Utility IRP. Nothing in this provision limits the Council's ability to take any action with respect to the IRP that is within its authority, including the Council's ability to open a prudence investigation for noncompliance on the part of the Utility.

F. The Council's acceptance of the Utility's IRP as described herein shall have no precedential effect with respect to the Council's evaluation of any application for approval of the acquisition, implementation, or deactivation of any supply-side or demand-side resource or program.

Attachment B
To Resolution R-26-____

REVISED ELECTRIC UTILITY INTEGRATED RESOURCE PLAN RULES
of the
Council of the City of New Orleans

ATTACHMENT B
TO RESOLUTION R-17- 429

ELECTRIC UTILITY INTEGRATED RESOURCE PLAN RULES
of the
Council of the City of New Orleans

ELECTRIC UTILITY INTEGRATED RESOURCE PLAN RULES
of **the**
Council of the City of New Orleans

These IRP Rules are intended to inform and empower effective Council and utility decision-making, while augmenting utility resource planning and enhancing public awareness of and input into the utility's energy choices. It is the Council's desire that a comprehensive IRP conducted in accordance with these IRP Rules provide a full picture of all reasonably available resource options in light of current and expected market conditions and technology trends, and generate an informed understanding of the economic, reliability, and risk evaluation of utility resource planning as well as the associated social and environmental impacts. Further, the Council wishes to encourage and enforce a transparent process that allows all interested constituents and stakeholders to participate and that fosters the development of a complete administrative record upon which informed Council decision-making can occur.

Section 1. Overview

A. These rules supersede the "Electric Utility Integrated Resource Plan Rules of the City of New Orleans" adopted by Council Resolution R-17-332. The purpose of these rules is to establish an open and transparent process by which all electric utilities, subject to the Council of the City of New Orleans (Council) regulatory jurisdiction, develop and file Integrated Resource Plans (IRP).

B. Each IRP triennial planning cycle shall be commenced with an Initiating Resolution of the Council which outlines the IRP process and timeline; Intervenor and public participation, policy objectives for consideration in the IRP, and other matters as deemed necessary by the Council.

C. Each Utility IRP shall include a matrix of these rules, the corresponding section of the IRP responsive to that rule, and a brief description of how the Utility complied with the rules.

D. Each Utility IRP is intended to serve as a general resource planning tool to the Utility and the Council, rather than a forum for the approval of the acquisition, implementation, or deactivation of any supply-side or demand-side resource.

E. To the extent there is non-compliance with these rules, after the showing of cause, consistent with the provisions of Chapter 158 Article III, Division II, Sec. 158-26 of the Code of the City of New Orleans and all applicable due process requirements, the Council may impose penalties for non-compliance with these rules.

Section 2. **Definitions**

A. ln these rules, unless otherwise specified, the following te1ms shall have the meaning defined in this Section:

1. "Advanced Metering Infrastructure" (AMI) - refers to meters and their underlying technology, including communication and data handling systems, that record

customer usage for time intervals of one hour or less, and can transmit information to the Utility without the need for a human meter reader. The meter allows for two-way flow of information and can notify the Utility of a power outage, and facilitate Demand Response programs.

2. "Advisors" - refers to the legal and technical consultants retained by the Council to assist it in its regulatory responsibilities.

3. "CURO" - refers to the Council Utilities Regulatory Office.

4. "Demand Side Management" (DSM) - refers to energy efficiency and Demand Response programs administered by the Utility. It includes the planning, implementation, and monitoring activities designed to modify energy usage patterns.

5. "Demand Response" (DR) - refers to a DSM program that seeks to modify customer loads to reduce or shift loads from hours with high electricity costs (peak hours) or reliability constraints to other hours. Demand Response programs include, but are not limited to: (a) those load-control programs that are dispatchable or controlled by the Utility, such as interruptible loads and direct load control of energy storage and end-use loads, including appliances, and(b) those load-control programs that are not controlled by the Utility, but rather involve a customer response during peak periods, such as critical peak pricing, time-of-use (TOU) rates, and any other rate design that sends market signals to customers to encourage reducing or shifting loads during peak hours. Demand Response also includes any other programs that shift loads from higher- to lower-energy cost times that may become available through the deployment of AMI or other technologies.

6. “Demand-Side Resources” – refers to those resources which impact the energy and peak demand served by the Utility, including DSM and the Distributed Energy Resource capacity which impacts utility customers’ peak and energy usage.

7. "Distributed Energy Resources" (DERs) - refers to generation or energy storage facilities owned or leased by retail customers, third parties, or the Utility that are interconnected to the Utility distribution grid and capable of delivering energy to the distribution grid. Distributed Energy Resources may include renewable/non-renewable generators, combined heat and power, energy storage technology (including electric vehicles), and any other technology that may similarly serve or dispatch energy to the distribution grid.

8. “‘Distributed Resources’ – refers to both Demand Side Management and Distributed Energy Resources

9. "Initiating Resolution" - refers to a resolution of the Council which initiates the triennial IRP planning cycle, enumerates related Council policies, and establishes the procedural schedule and such other matters as the Council deems appropriate, including the process to be utilized by the Utility, stakeholders and Interested Parties throughout the IRP development process.

10. "Integrated Resource Planning" - is an open, transparent planning process through which all relevant supply-side and demand-side resources (including all distributed resources), and the factors influencing choice among them, while integrating transmission and distribution planning into the overall resource planning process, are investigated for the optimal set of resources to meet current and future electric service needs at the lowest total cost to customers and the Utility, in a manner consistent with the long-run public interest, given the expected combination of costs, benefits, reliability, risks and uncertainty.

11. "Interested Person" - refers to an individual or entity who desires to receive information and notices of public meetings as part of the IRP process and who is not a party to the proceeding. CURO shall maintain a list of Interested Persons and forward to them copies of all filings, issuances, and notices occurring in the proceeding. This may be accomplished through the Council's electronic docketing system once that docketing system develops the necessary capabilities.

12. "Intervenor" - refers to persons who have intervened in the case pursuant to the New Orleans, Louisiana Code of Ordinances, Chapter 158, Article III.

13. "Load Forecast"- refers to a forecast of electricity demand (MW) and energy (MWh) for the Utility that takes into account currently implemented demand-side management and distributed energy resources, but does not include any anticipated or incremental demand-side resources.

14. Load Modifying Resource – refers to a Midcontinent Independent System Operator (MISO) market participant asset used during capacity emergencies to maintain grid reliability by reducing electricity consumption/demand or by dispatching backup generation when called upon (as with certain DERs or solar stations in standby availability).

15. "New Orleans Technical Reference Manual" (NOTRM) - refers to a common reference document for estimating energy and peak demand reduction ("deemed savings") resulting from the installation of DSM measures promoted by utility-administered programs in New Orleans. This document is a compilation of deemed savings values previously approved by the Council and the Advisors for use in estimating savings for DSM measures. The NOTRM is updated periodically as required by the Council through a collaborative process involving the Council, the Advisors, the Utility, the Third Party Administrator and the third party Evaluation, Measurement and Verification ("EM&V") contractor, and other parties as needed. The data and methodologies in this document are to be used by program planners, administrators, implementers and evaluators for forecasting, reporting and evaluating energy and demand savings, costs, and other metrics from demand-side measures installed in New Orleans.

16. "Planning Period" - refers to the number of projected years over which the existing resources and various potential resource options are evaluated in the IRP process.

17. "Planning Scenario"- refers to a distinct definition of a market outlook for the IRP Planning Period consisting of key parameters which are not controlled by the Utility

or the Council. Several Planning Scenarios are constructed to identify the plausible futures of the IRP Planning Period. Various Planning Strategies are then evaluated relative to each of the defined Planning Scenarios.

18. "Planning Strategy" - refers to the defining of distinct resource constraints, regulatory policies, or business decisions over which the Council, the Utility, or Intervenors have control. For example, a Planning Strategy can be traditional utility planning, intervenors defining resource inputs, or a Planning Strategy reflecting Council policies. Each distinct Planning Strategy is evaluated relative to each Planning Scenario, resulting in an optimized Resource Portfolio for each Planning Scenario/Planning Strategy combination.

19. "Resource Portfolio"- refers to prescribed combinations of supply-side resources, demand-side resources, and transmission and distribution investment for comparative evaluation in IRP modeling and reporting. Modeling of the intersection of a Planning Scenario and a Planning Strategy results in an optimized Resource Portfolio with a defined cost and associated risk. For example, if four Planning Scenarios and two separate Planning Strategies are defined, there would be eight Resource Portfolios.

20. "Regional Transmission Organization" (RTO) - refers to the Midcontinent Independent System Operator (MISO) or any successor RTO of which the Utility is a participating member.

21. "Stakeholder" - refers to any person potentially impacted by the outcome of the IRP, whether that person formally intervenes in the proceeding or not.

22. "Stakeholder Process" - refers to the meaningful engagement of stakeholders throughout the IRP process, specifically addressed in the Initiating Resolution commencing an IRP cycle.

23. "Supply-Side Resources" – refers to those resources which provide the load and capability, in terms of kW and/or kWh, to meet the Utility's current and projected resource needs and load requirements during the Planning Period. Supply-Side Resources include Utility-owned resources and purchased power agreements (PPAs), third-party PPAs, Load Modifying Resources, and DER capacity used to meet Utility resource needs and load requirements.

24. "Utility"- refers to any electric utility subject to the Council's regulatory jurisdiction.

Section 3. Objectives

A. The Utility shall state and support specific objectives to be accomplished in the IRP planning process, which include but are not limited to the following:

1. optimize the integration of Supply-Side resources and Demand-Side resources, while taking into account transmission and distribution planning, to provide New Orleans ratepayers with reliable electricity at the lowest practicable cost given an acceptable level of risk;

2. maintain the Utility's financial integrity;

3. anticipate and mitigate risks associated with fuel and market prices, environmental compliance costs, and other economic factors;

4. support the resiliency and sustainability of the Utility's systems in New Orleans;

5. comply with local, state and federal regulatory requirements and regulatory requirements and known policies (including such policies identified in the Initiating Resolution) established by the Council;

6. evaluate the appropriateness of incorporating advances in technology, including, but not limited to, renewable energy, energy storage, and DERs, among others;

7. achieve a range of acceptable risk in the trade-off between cost and risk; and

8. maintain transparency and engagement with stakeholders throughout the IRP process by conducting technical conferences and providing for stakeholder feedback regarding the Planning Scenarios, Planning Strategies, input parameters, and assumptions.

B. ln the IRP Report, the Utility shall discuss its efforts to achieve each of the objectives identified in Section 3A and any additional specific objectives identified in the Initiating Resolution.

Section 4. **Load Forecast**

A. The Utility shall develop a reference case Load Forecast and at least two alternative Load Forecasts applicable to the Planning Period which are consistent with the Planning Scenarios identified in Section 7C. The following data shall be supplied in support of each Load Forecast:

I. The Utility's forecast of demand and energy usage by customer class for the Planning Period;

2. A detailed discussion of the forecasting methodology and a list of independent variables and their reference sources that were utilized in the development of the Load Forecast, including assumptions and econometrically evaluated estimates. The details of the Load Forecast should identify the incremental energy and demand impacts of projected Utility-sponsored DSM program additions and DER capacity which impact Utility kW and kWhs, as well as the then existing DER capacity and Utility-sponsored DSM programs. The load forecast should reflect as decrements to load, the organic adoption of customer-controlled DERs, such as net metered solar;

3. Forecasts of the independent variables for the Planning Period, including their probability distributions and statistical significance;

4. The expected value of the Load Forecast as well as the probability distributions (uncertainty ranges) around the expected value of the Load Forecast; and

5. A discussion of the extent to which line losses have been incorporated in the Load Forecast.

6. Specific data supporting the individual decrements to the Load Forecast attributed to DSM programs, DER capacity, and behind-the-meter/ net-energy-metering solar, recognizing the availability of modeling input variables.

B. The Utility shall construct composite customer hourly load profiles based on the forecasted demand and energy usage by customer class and relevant AMI and load research data, including the factors which determine future load levels and shape.

C. Concurrent with the presentation of the Load Forecasts to the Advisors, CURO, and stakeholders, the Utility shall provide historical demand and energy data for the five (5) years immediately preceding the Planning Period. At a minimum, the following data shall be provided:

1. monthly energy consumption for the Utility in total and for each customer class;

2. monthly coincident peak[1] demand for the Utility and estimates of the monthly coincident peak demand for each customer class;[2] and

3. estimates of the monthly peak demand for each customer class;[3]

D. The data and discussions developed pursuant to Section 4A and Section 4B, and Section 4C shall be provided as an attachment to the IRP report and summarized in the IRP report.

E. The Utility shall also provide a list of any known co-generation resources, community solar, and DERs existing on the Utility's system, including resources maintained by the City of New Orleans for city/parish purposes, (e.g. Sewerage and Water Board, Orleans Levee District, or by independent agencies or entities such as universities, etc.).

Section 5. Resource Options

A. Identification of resource options. The Utility shall identify and evaluate all existing Supply-Side and Demand-Side resources and identify a variety of potential Supply-Side and Demand-Side resources which can be reasonably expected to meet the Utility's projected resource needs during the Planning Period.

1. Existing Supply-Side resources. For existing Supply-Side resources, including Distributed Resources, the Utility should incorporate all fixed and variable costs necessary to continue to utilize the resource as part of a Resource Portfolio. Costs shall include the costs of any anticipated renewal and replacement projects as well as the cost of regulatory mandated current and future emission controls.

   a. The Utility shall identify important changes to the Utility's existing Supply-Side resource mix that occurred since the last IRP including large capital projects, resource procurements, LMRs, DERs, changes in fuel types, and actual or expected operational changes regardless of cause.

   b. Data supplied as part of the Utility's IRP filing should include a list of the Utility's existing Supply-Side Resources, including Distributed Resources, with the list to

[1] For the purposes of Section 4C, "monthly coincident peak" refers to the peak coincident with the RTO monthly peak.
[2] To the extent ENO has or attains the technical capability to collect load data on a customer class level, it shall collect and report the historic data in lieu of the customer class level estimates.
[3] To the extent ENO has or attains the technical capability to collect load data on a customer class level, it shall collect and report the historic data in lieu of the customer class level estimates.

include: the resource name, fuel type, capacity rating at time of summer and winter peak, and typical operating role (e.g. base, intermediate, peaking).

2. For existing demand-side resources, including Distributed Resources, the Utility should account for load reductions attributable to the then-existing Demand-Side Resources in each year of the Planning Period. Each existing Demand-Side Resource will be identified as either a specific energy efficiency/DR program with an individual program lifetime, a DER resource, or other Demand-Side Resource (e.g. NEM), with the estimated energy and demand reductions applicable to the Planning Period associated with each existing Demand-Side Resource. Data supplied as part of the Utility's IRP filing should include:

   a. Details of projected kWh/kW reductions from existing DSM programs based on quantifiable results and other credible support derived from Energy Smart New Orleans, or any successor program, using verified data available to the Utility from prior DSM program implementation years.

   b. Details of projected kWh/kW reductions from existing DER and other Demand-Side Resources (e.g. NEM) based on supporting documentation.

   c. A list categorizing the Utility's existing Demand-Side Resources including anticipated capacity at time of summer and winter peak.

3. With respect to potential Supply-Side Resources, including Distributed Resources, the Utility shall consider: Utility-owned and purchased power resources; third-party PPAs, conventional and new generating technologies including technologies expected to become commercially viable during the Planning Period; technologies utilizing renewable fuels; energy storage technologies; cogeneration resources; and Distributed Energy Resources; among others.

   a. The Utility should incorporate any known Council policy goals (including such policy goals identified in the Initiating Resolution) with respect to resource acquisition, including, but not limited to, renewable resources, energy storage technologies, and DERs, including relevant data from current dockets applicable to the Planning Period.

   b. Data supplied as part of the Utility's IRP filing should include: a description of each potential Supply-Side Resource including a technology description, operating characteristics, capital cost or demand charge, fixed operation and maintenance costs, variable charges, variable operation and maintenance costs, earliest date available to provide supply, expected life or contractual term of resource, and fuel type with reference to fuel forecast.

4. Potential Demand-Side resources. With respect to potential Demand-Side Resources, the Utility should consider and identify all cost-effective and Council-approved Demand-Side Resources through the development of a DSM Potential Study and other analyses of Demand-Side Resources accepted by Council. The cost-effectiveness of Demand-Side Resources can be determined by the Total Resource Cost ("TRC") and Ratepayer Impact Measure ("RIM") benefit-cost analyses ("BCA"), or other BCA tests, such as the National Standards Practice Manual[4], as specified under the Council's Policy Objectives

[4] The National Standards Practice Manual for Benefit Cost Analysis of Distributed Energy Resources, 2026 edition,

in the IRP Initiating Resolution. All DSM measures with a Total Resource Cost Test[5] value of 1.0 or greater shall be considered cost-effective for DSM measure screening purposes.

a. The DSM Potential Study shall include, but not be limited to: identification of eligible measures, measure life expectancies, baseline standards, load reduction profiles, incremental capacity and energy savings, measure and program cost assumptions, participant adoption rates, market development, and avoided energy and capacity costs for DSM measure and program screening purposes. The scope of the DSM potential study should include an assessment of potential DERs as standalone grid-connected devices in addition to the DSM and DR potential normally studied. DERs should be disaggregated by type for the purposes of modeling and evaluation.

b. The principal reference document for the DSM potential study, DERs, and other Demand-Side Resources shall be the New Orleans Technical Reference Manual.

c. In the development of the DSM Potential Study, BCA tests addressed herein and in the Initiating Resolution will be calculated for the DSM measures and programs considered.

d. The Utility should incorporate any known Council policy goals or targets (including such policy goals or targets identified in the Initiating Resolution) with respect to Demand-Side Resources.

e. The cost-effective DR programs should include consideration of those programs enabled by the deployment of Advanced Meter Infrastructure, including both direct load control and DR pricing programs for both Residential and Commercial customer classes.

f. Data supplied as part of the Utility's IRP filing should include: a description of each potential Demand-Side Resource considered, including a description of the DER resource or DSM program; expected penetration levels by planning year; hourly load reduction profiles for each potential Demand-Side Resource utilized in the IRP process; and results of appropriate cost-benefit analyses and acceptance tests, as part of the planning assumptions utilized within the IRP planning process.

g. The Council will make a decision and announce it in the Initiating Resolution whether it will procure an independent consultant to perform a DSM Potential Study. ln the event the Council does not procure an independent contractor, ENO shall provide a DSM Potential Study.[6]

B. Through the Stakeholder Process, the Utility shall strive to develop a position agreed to by the Utility, the Advisors, and a majority of the Intervenors regarding the potential Supply-Side and potential Demand-Side Resources and their associated defining characteristics (e.g., capital cost,

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and its compendium, Benefit-Cost Analysis Case Studies, are publications of National Association of State Energy Officials (NASEO), developed by NASEO's National Energy Screening Project (NESP). The DERs addressed in this Manual include: Energy efficiency (EE), Demand response (DR), Distributed generation (DG), Distributed storage (DS), and Electrification-related DERs.

[5] California Standard Practice Manual: Economic Analysis of Demand-Side Programs and projects, State of California Governor's Office of Planning and Research July 2002.

[6] This provision does not preclude any party from entering their own DSM potential study into the docket

operating and maintenance costs, emissions, potential DSM supply curve, DER supply-side and demand-side capacity, etc.).

1. To the extent such a consensus can be achieved among the Utility, the Advisors, and a majority of the Intervenors,[7] the resulting collection of potential Supply-Side and Demand-Side Resources and their associated defining characteristics will be utilized in the reference Planning Strategy developed pursuant to Section 7D.

2. To the extent such a consensus cannot be achieved, the Utility shall model, in coordination with the requirements in Section 7D, two distinct Planning Strategies: a reference Planning Strategy and a stakeholder Planning Strategy. The reference Planning Strategy will be based on the Utility's assessment of the collection of potential Supply-Side and Demand-Side Resources and their associated defining characteristics. The stakeholder Planning Strategy will be determined by a majority of the Intervenors and modeled by the Utility based on inputs provided to the Utility describing the collection of potential Supply-Side and Demand-Side Resources and their associated defining characteristics.[8] To maintain consistency in the modeling process, the Advisors will work with the Intervenors and the Utility to: ensure that input that is provided for the stakeholder Planning Strategy can be accommodated within the framework of the existing models and software.[9]

Section 6. Transmission and Distribution

A. The Utility shall explain how the Utility's current transmission and distribution systems, and any planned transmission and distribution system expansions (including regional transmission system expansion planned by the RTO in which the Utility participates) are integrated into the overall resource planning process to optimize the Utility's resource portfolios and provide New Orleans ratepayers with reliable electricity at the lowest practicable cost.

B. Models developed for the integrated resource planning process should incorporate the planned configuration of the Utility's transmission and distribution systems, and the interconnected RTO during the Planning Period. A distribution system "non-wires alternative" study should be considered as part of the IRP process to identify possible DER projects and evaluate the costs and benefits that could be included in the portfolio optimization; such study can be executed in parallel with the DSM Potential Study

C. To the extent major changes in the operation or planning of the transmission system and/or distribution system (including changes to accommodate the expansion of DERs) are contemplated in the Planning Period, the Utility should describe the anticipated changes and provide an assessment of the cost and benefits to the Utility and its customers.

D. To the extent that new resource additions are selected by the Utility for a Resource Portfolio based on reliability needs rather than as a result of the optimized development of a Resource Portfolio, the Utility shall identify reasonable transmission and/or distribution solutions that can

[7] An Intervenor not consenting to the majority position and thus not joining in the consensus retains the ability to oppose the consensus position before the Council and assert its own position.
[8] An Intervenor not consenting to the majority position retains the ability to oppose the consensus position before the Council and assert its own position.
[9] The Utility shall have no obligation to incorporate element(s) of the stakeholder Planning Strategy that cannot be accommodated by the Utility's modeling capabilities.

be employed to either reduce the size, delay, or eliminate the need for the new reliability-driven resource additions, and provide economic analyses demonstrating why the new reliability-driven resource addition was selected in lieu of the transmission and/or distribution solutions identified.

E. It is the Council's intent that, as part of the IRP, the Utility shall evaluate the extent to which reliability of the distribution system can be improved through the strategic location and timing of DERs or other resource additions identified as part of the IRP planning process. The Utility should provide an analysis, discussion, and quantification of the costs and benefits as part of the evaluation. To the extent the Utility does not currently have the capability to meet this requirement, the utility shall demonstrate progress toward accomplishing this requirement until such time as it acquires the capability.

Section 7. **Integrated Resource Plan Analyses**

A. The integrated resource planning process should include modeling of specific parameters and their relationships consistent with market fundamentals, and *as* appropriate for long-term Integrated Resource Portfolio planning. This overall modeling approach is an accepted analytic approach used in resource planning considering the range of both Supply-Side and Demand-Side Resource options as well as uncertainty surrounding market pricing. To represent and account for the different characteristics of alternative types of resource options, mathematical methods, such as a linear programming formulation, could be used to optimize resource decisions.[10]

B. The optimization process shall be constrained to mitigate the over-reliance on forecasted revenues from external capacity market sales and external energy market sales driving the selection of resources.

C. The Utility shall develop three to four Planning Scenarios that incorporate different economic and environmental circumstances and national and regional regulatory and legislative policies.

D. The Planning Scenarios should include a Reference Planning Scenario that represents the Utility's point of view on the most likely future circumstances and policies, as well as two alternative Planning Scenarios that account for alternative circumstances and policies.

1. In the development of the Planning Scenarios, the Utility should seek to develop a position agreed to by the Utility, Advisors, and a majority of Intervenors[11] regarding the assumptions surrounding each of the Planning Scenarios. To the extent such a consensus is not reasonably attainable regarding the Planning Scenarios, the Utility shall model a fourth Planning Scenario which is based upon input agreed to by a majority of the Intervenors.[12]

[10] Linear programming is a mathematical method or model of optimizing Jinem functions or relationships within constraints to achieve the lowest costs.

[11] An Intervenor not consenting to the majority position and thus not joining in the consensus retains the ability to oppose the consensus position before the Council and assert its own position.

[12] An Intervenor not consenting to the majority position and thus not joining in the consensus retains the ability to oppose the consensus position before the Council and assert its own position.

2. For each IRP Planning Scenario, data supplied as part of the Utility's IRP filing should include:

   a. a fuel price forecast for each fuel considered for utilization in any existing or potential supply-side resource;

   b. an hourly market price forecast for energy (e.g. locational marginal prices);

   c. an annual capacity price forecast for both a short-term capacity purchase *(e.g.* bilateral contract or Planning Resource Credit) and a long-term capacity purchase (e.g. long-run marginal cost of a new replacement gas combustion turbine); and

   d. forecasts of price for any other price-related components that are defined by the Planning Scenario (e.g. CO2 price forecast, etc.).

E. Distinct from the Planning Scenarios, the Utility shall identify two to four Planning Strategies which constrain the optimization process to achieve particular goals, regulatory policies and/or business decisions over which the Council, the Utility, or Stakeholders have control.

1. The Utility shall develop a Planning Strategy that allows the optimization process to identify the lowest cost option for meeting the needs identified in the IRP process.

2. The Utility shall develop a Reference Planning Strategy agreed to by the Utility, Advisors, and a majority of the intervenors.[13] To the extent such a consensus cannot be reasonably achieved, the Reference Planning Strategy shall reflect the Utility's point of view on resource input parameters and constraints, and the Utility shall model a separate Stakeholder Planning Strategy based upon input determined by a majority of the Intervenors.[14]

3. As necessary, the Utility shall develop alternate Planning Strategies to reflect known utility regulatory policy goals of the Council (including such policy goals or targets identified in the Initiating Resolution) as established no later than 30 days prior to the date the Planning Strategy inputs must be finalized.

F. Prior to the development of optimized Resource Portfolios, the parameters developed for the Planning Scenarios and Planning Strategies shall be set, considered finalized, and not subject for alteration during the remainder of the IRP planning cycle. The IRP Report shall describe the parameters of each Planning Scenario and each Planning Strategy, including all artificial constraints utilized in the optimization modeling.

G. Resource Portfolios shall be developed through optimization utilizing the Utility's modeling software. The Utility shall identify the least-cost Resource Portfolio for each Planning Scenario and Planning Strategy combination, based on total cost. Resource Portfolios shall consist of optimized combinations of Supply-Side and Demand-Side Resources, including potential DSM programs selected from the DSM Potential Study and application of DER capacity, while

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[14] An Intervenor not consenting to the majority position and thus not joining in the consensus retains the ability to oppose the consensus position before the Council 1mcl assert its own position.

recognizing constraints including transmission and distribution planning. Manual portfolios can be used to evaluate specific types and amounts of DERs as a method of portfolio development.

H. The Utility shall provide (i) a discussion and presentation of results for each Planning Scenario/Planning Strategy combination, (ii) the annual total demand-related costs, energy-related costs, and total supply costs associated with each least-cost Resource Portfolio identified under each Planning Scenario/Planning Strategy combination, (iii) a load and capability table indicating the total load requirements and identifying all Supply-Side and Demand-Side Resources included in the Resource Portfolio, (iv) the annual impacts of existing Demand-Side Resources on the total load requirements, and the annual impacts of potential DSM and DERs in Resource Portfolio Optimization, and (v) a description of the potential Supply-Side and Demand-Side Resources that are projected for the Planning Period and, if applicable, their principal rationale for selection (i.e., supply peak demand, supply non-peak demand, operational and policy constraints, achieve more economical production of energy, etc.).

1. Data supplied as part of the Utility's IRP filing shall include a cumulative present worth summary of the results as well as the annual estimates of Supply-Side and Demand-Side Resource costs that result in the cumulative present worth to enable the Council to understand the timing of costs and savings of each least-cost Resource Portfolio.

I. The IRP report's discussion and presentation of results for each Resource Portfolio should identify key characteristics of that Resource Portfolio and significant factors that drive the ultimate cost of that Resource Portfolio such that the Council may understand which factors could ultimately and significantly affect the preference of a Resource Portfolio by the Council.

J. The Utility will develop and include a scorecard template or set of quantitative and qualitative metrics to assist the Council in assessing the IRP based on the Resource Portfolios. The scorecard should rank the Resource Portfolios by how well each portfolio achieves each metric. Such metrics should include but not necessarily be limited to: cost[15]; impact on the Utility's revenue requirements; risk; flexibility of resource options[16]; DER policy and those resource portfolios that include DERs, reasonably quantifiable environmental impacts (such as national average emissions for the technologies chosen, amount of groundwater consumed, etc.); consistency with established, published city policies, such as the City's sustainability plan; and macroeconomic impacts in New Orleans.

Section 8. Risk Analyses

A. The Utility shall develop a cost/risk analysis which balances quantifiable costs with quantifiable risks of the identified least-cost Resource Portfolios. The risk assessment must be presented in the IRP to allow the Council to comprehend the robustness of each Resource Portfolio across the cost/risk range of possible Resource Portfolios.

1. In quantifying Resource Portfolio costs/risks, the IRP shall assess any social and environmental effects of the Resource Portfolios to the extent that; l) those effects can be

[15] The cost metric should include the cost of quantified externalities as well as Utility costs resulting from the lRP optimization.
[16] The flexibility metric includes response to load swings and quick start.

quantified and have been modeled for a Resource Portfolio, including the applicable Planning Period years and ranges of uncertainty surrounding each externality cost, and 2) each quantified cost must be clearly identified by the portion which relates to the Utility's revenue requirements or cost of providing service to the Utility's customers under the Resource Portfolio.

2. It is the Council's intent that, as part of the IRP, a risk assessment be conducted to evaluate both the expected outcome of potential costs as well as the distribution and potential range and associated probabilities of outcomes. To the extent the Utility believes the risk assessment described herein is beyond the current modeling capabilities of the Utility or that the risk assessment cannot be accomplished within the procedural schedule set forth in the Initiating Resolution, the Utility shall so inform the Council and meet with the Intervenors and Advisors to agree upon an alternative form of risk analysis to recommend to the Council.

    a. The risk assessment shall include the expected cost per MWh of the Resource Portfolios in selected future years, along with the range of annual average costs foreseen for the 10th and 90th percentiles of simulated possible outcomes.

    b. The supporting methodology shall be included, such as the iterations or simulations performed for the selected years, in which the possible outcomes are drawn from distributions that describe market expectations and volatility as of the current filing date.

Section 9. IRP Process Requirements

A. At a minimum, the IRP process shall include, but not be limited to, the following elements:

1. The opportunity for Intervenors to participate in the concurrent development of inputs and assumptions for the major components of the IRP (including the DSM Potential Study and those resource portfolios that include DERs) in collaboration with the Utility within the confines of the IRP timeline and procedural schedule.

2. At least four technical meetings attended by the parties in the Docket focused on major IRP components that include the Utility, intervenors, CURO, and the Advisors with structured comment deadlines so that meeting participants have the opportunity to present inputs and assumptions and provide comments, and attempt to reach consensus while remaining mindful of the procedural schedule established in the Initiating Resolution.

3. At least 3 public engagement technical conferences advertised through multiple media channels at a minimum of 30 days prior to the public technical conference.

    a. A public education and kickoff meeting that explains the following: the purpose of the IRP and the corresponding process; the IRP timeline as delineated in the Council's Initiating Resolution with respect to major process deadlines; the inputs and assumptions that are considered in the IRP process and summarized in the report; and ways in which public can remain informed throughout the IRP cycle (e.g., online information resources that provide status updates, portal through which customers can submit questions or concerns to the Utility);

b. A public presentation of the IRP; and

c. A public hearing opportunity after presentation of the IRP report to give the public the opportunity to provide comment on the record.

4. CURO shall schedule, provide notice of, and conduct the public technical conferences. In addition to a live presentation, all public technical conferences should also be broadcast via the Council's website and archived for later viewing.

Section 10. Submission and Public Presentation of IRP

A The Utility shall make its IRP available for public review subject to the provisions of the Council Resolution initiating the current IRP planning cycle and referenced in Section 1B.

B. The Utility shall file its IRP with the Council consistent with and subject to the provisions of the Council Resolution initiating the current IRP planning cycle referenced in Section 1B.

C. The IRP report should discuss the stakeholders' engagement throughout the IRP process; the access to data inputs and specific modeling results by all parties; the consensus reached regarding all Demand-Side and Supply-Side Resource inputs and assumptions, including application/integration of DERs; specific descriptions of unresolved issues regarding inputs, assumptions, or methodology; the formulation of the stakeholder Planning Scenario and/or Stakeholder Planning Strategy as needed; and recommendations to improve the transparency and efficiency of the IRP process for prospective IRP cycles.

D. The IRP shall include an action plan and timeline discussing any steps or actions the Utility may propose to take as a result of the IRP, understanding that the Council's acceptance of the filing of the Utility's IRP would not operate as approval of any such proposed steps or actions.

E. Provided the IRP fulfills the requirements contained herein and was developed in compliance with the procedural schedule established for the triennial IRP cycle, the Council shall accept the Utility's IRP as filed in compliance with the Council's substantive and procedural requirements. Failure of the utility to substantially comply with the provisions of these Rules may result in summary rejection of the Utility's IRP. Such rejection may be without prejudice to the refiling of the IRP once the utility has corrected the deficiencies. Further, after consideration of all of the evidence entered into the record, the Council may approve the accepted Utility IRP, approve it subject to stated conditions, approve it with modifications, approve it in part and reject it in part, reject it in its entirety, or choose to terminate the proceeding without either approving or rejecting the accepted Utility IRP. Nothing in this provision limits the Council's ability to take any action with respect to the IRP that is within its authority, including the Council's ability to open a prudence investigation for noncompliance on the part of the Utility.

F. The Council's acceptance of the Utility's IRP as described herein shall have no precedential effect with respect to the Council's evaluation of any application for approval of the acquisition, implementation, or deactivation of any supply-side or demand-side resource or program.