BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

IN RE: APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	**)))))**	**DOCKET NO. UD-16-02**

DIRECT TESTIMONY

OF

VICTOR M. PREP, P.E.

ON BEHALF OF

THE ADVISORS TO THE

COUNCIL OF THE CITY OF NEW ORLEANS

PUBLIC REDACTED VERSION

NOVEMBER 20, 2017

PREPARED DIRECT TESTIMONY

OF

VICTOR M. PREP

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Victor M. Prep. My business address is 8055 East Tufts Avenue, Suite 1250, Denver, Colorado. I am a registered Professional Engineer in the States of Pennsylvania, Colorado, and Louisiana and I am an Executive Consultant with the firm, Legend Consulting Group Limited ("Legend").

Q. ON WHOSE BEHALF DO YOU APPEAR IN THIS PROCEEDING?

A. I am presenting testimony on behalf of the Advisors to the Council of the City of New Orleans ("Council" or "CNO"). The Council regulates the rates, terms, and conditions of electric and gas service of Entergy New Orleans, Inc. ("ENO"). ENO is one of the Entergy Operating Companies[1] and is a wholly-owned subsidiary of Entergy Corporation ("Entergy").

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[1] The Entergy Operating Companies ("Operating Companies") are Entergy Arkansas, Inc. ("EAI"); Entergy Louisiana, LLC ("ELL"); Entergy Mississippi, Inc. ("EMI"); Entergy Texas, Inc. ("ETI"); and ENO.

Q. PLEASE SUMMARIZE YOUR RELEVANT EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. Exhibit No. ___ (VMP-2) provides a summary of my relevant education and professional experience and Exhibit No. ____(VMP-3) lists my previous testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide my recommendations regarding appropriate methodologies to allocate the fixed project costs in the Docket as well as the results of my evaluation of ENO's proposed Regulatory Approval Plan related to ENO's initial and supplemental applications: its "*Application of Entergy New Orleans, Inc. for Approval to Construct New Orleans Power Station and Request for Cost Recovery and Timely Relief*" ("Initial Application"); and its July 6, 2017, "*Supplemental and Amending Application of Entergy New Orleans, Inc. ("ENO") for Approval to Construct New Orleans Power Station and Request for Cost Recovery and for Timely Relief.* ("Supplemental Application"). I refer to these filing collectively as the "Application". In particular, I will address alternative regulatory treatments to recover project costs, including cost recovery through base rates in the Combined Rate Case in lieu of another additional Rider on customer bills as proposed by ENO. I will also discuss an approach to estimating the allocated project costs and provide recommendations regarding the allocation and cost recovery of Long Term Service Agreement ("LTSA") costs. And I will present a comparative table of the differing demand side management ("DSM") reductions to annual system peaks that ENO used in its various analyses.

Q. PLEASE SUMMARIZE YOUR MAJOR CONCLUSIONS AND RECOMMENDATIONS.

A. In my testimony, I discuss four major areas where I provide conclusions and recommendations. First, regarding the allocation of project non-fuel/fixed costs to customer classes, I conclude that a demand cost allocation methodology is much more appropriate than a kWh-based allocation. For the purposes of projecting customer class and rate impacts related to NOPS project revenue requirements, I recommend that base rate revenue be used to develop a current estimate of the project fixed costs allocated to customer classes, with the final allocation methodology to be determined in the Combined Rate Case.

Second, since the anticipated commercial operation date ("COD") of each of the New Orleans Power Station ("NOPS") alternatives is anticipated to be later than the test periods and effective dates of revised rates from the Combined Rate Case, I recommend that the recovery of project fixed costs be accomplished using a two-step increase or adjustment to base rates. Following the rate adjustment from the Combined Rate Case expected by the first billing cycle of August 2018, the second rate adjustment (based on project fixed costs as pro-forma adjustments in the rate case test period) would occur with the COD when the approved NOPS project is used and useful and placed in service. I do not recommend recovery of project fixed costs through a rider as proposed by ENO.

Third, I recommend that the project costs be evaluated in conjunction with the total costs of ENO (including the return component), where a total ENO retail revenue adjustment is determined based on a comprehensive evaluation of all costs and revenues. The evaluation of total ENO fixed costs and related revenue adjustment will occur annually, with either a decoupling mechanism required by Resolution R-16-103[2] or with an annual Formula Rate Plan ("FRP") filing if approved in the Combined Rate Case. If an FRP is approved with an ROE bandwidth calculation, the NOPS project fixed cost recovery should be included with the evaluation of ENO's total fixed costs within the ROE bandwidth calculation.

Fourth, I conclude that the LTSA costs are primarily fixed costs similar to traditional project fixed maintenance costs, and should be recovered through base rates using appropriate cost allocations, rather than recovery through the fuel adjustment clause ("FAC") as proposed by ENO.

II. EVALUATION OF ENO'S APPLICATION BEFORE THE COUNCIL

Q. WHAT IS ENO SEEKING IN THIS DOCKET?

A. In its Application, ENO seeks authorization to proceed with constructing the New Orleans Power Station ("NOPS" or the "Project"). ENO amended the Initial Application to include an alternative to the original Project configuration of a 226 MW combustion turbine ("CT"). The alternative that ENO proposes is a 128 MW project, or an alternative peaker, consisting of seven Reciprocating Internal Combustion Engine ("RICE") generator sets ("RICE alternative"). ENO has also analyzed another alternative

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[2] Resolution No. R-16-103 required ENO to file three annual revenue decoupling adjustments following the Combined Rate Case, with or without an FRP approved by the Council.

or reference portfolio, a transmission alternative, consisting of transmission upgrades without any new local generation. In conjunction with its request for authorization to proceed with construction, ENO also proposed a Regulatory Approval Plan, seeking confirmation that ENO will have a full and fair opportunity to recover prudently incurred costs of the Project. Specifically, ENO's Application requested an exact cost recovery Rider to recover NOPS costs from the commencement of commercial operation.

Q. WHAT DOCUMENTS HAVE YOUR REVIEWED IN SUPPORT OF YOUR TESTIMONY?

A. I have reviewed ENO's complete Application and supporting exhibits, the filed testimony of all parties in the Docket, the discovery responses of all parties, and the relevant source references provided in the documents. In addition, I have conducted research concerning similar regulatory and cost recovery issues in several jurisdictions in support of the conclusions and recommendations in my testimony.

Q. HOW HAVE YOU STRUCTURED YOUR TESTIMONY IN SUMMARIZING YOUR EVALUATION OF ENO'S APPLICATION?

A. First, I will discuss appropriate methodologies to allocate the fixed costs of the NOPS alternatives, for a current estimate and for a basis of future examination. Second, I will evaluate ENO's Regulatory Plan, including ENO's proposals regarding a cost recovery Rider and its inclusion in annual revenue adjustments. Third, I will discuss how a fixed cost recovery Rider constitutes single issue ratemaking and should not be considered.

Fourth, I will discuss the fixed cost recovery of the viable alternative through a step (two-part) increase developed in the Combined Rate Case. Fifth, I will provide the regulatory basis for including the fixed cost recovery in the evaluation of ENO's total costs and earned return on equity. Sixth, I will address LTSA costs, describing them as predominately fixed long term maintenance costs, and providing for recovery through base rates. Seventh, I will present a comparative table showing the differing levels of DSM reduction to annual system peaks that were used in the analyses that ENO has conducted related to the NOPS project.

III. METHODOLOGY TO ALLOCATE PROJECT COSTS

Q. PLEASE SUMMARIZE THE APPROPRIATE COST ALLOCATION METHODOLOGIES THAT SHOULD BE CONSIDERED IN ALLOCATING THE FIXED PROJECT COSTS TO CUSTOMER CLASSES.

A. The allocation of fixed project costs should include a recognition of the peak demands plus reserve requirements throughout the year. An average hourly demand represented by kilowatt hours ("kWh"), as used in ENO's current Purchased Power Capacity Acquisition Cost Recovery ("PPCACR") Rider, is a volumetric basis which is inappropriate since it gives no weight to peak demands or the timing of cost incurrence. Conversely, customer class contributions at the hour of the annual system peak ignore the relative importance of other peak demands throughout the year where the mix of available resources and customer class contributions to those peak demands may vary. There are more innovative approaches to allocating fixed costs that have been used, such as applying weightings to peak demands and combining marginal cost concepts with the allocation of revenue requirements based on embedded or accounting costs. An in-depth examination of all applicable methodologies to allocate fixed costs should be completed for the Council's consideration in the Combined Rate Case.

Q. WHAT METHODOLOGY WAS USED IN ENO'S PREVIOUS RATE APPLICATIONS BEFORE THE COUNCIL TO ALLOCATE PRODUCTION AND TRANSMISSION VOLTAGE LEVEL FIXED COSTS TO CUSTOMER CLASSES?

A. The methodology used to allocate major project fixed costs in the last ENO Legacy[3] rate case and Algiers rate case was the average of customer class contributions to the 12 monthly system peaks. As is customary in each major rate application, a current examination of all cost allocation methodologies applicable to each functional cost and voltage level will be accomplished during the Council's consideration of ENO's Combined Rate Case anticipated to be filed by July 1, 2018. In this regard, the major project non-fuel costs of Union Power Station Power Block 1 & Ninemile 6 that have been recovered in the existing PPCACR Rider will be incorporated in the combined ENO base rates with the cost recovery realigned from a kWh based cost allocation to a cost allocation methodology that is more acceptable to recover production-related fixed costs**.** Typically, the various parties in rate applications often support differing positions

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[3] Prior to the 2016 Algiers Transaction, ENO's retail customer base excluded Algiers, and has been referenced as ENO Legacy. ENO's previous rate case for ENO Legacy was filed in 2008. ELL filed a rate case for Algiers in 2013.

regarding acceptable or appropriate cost allocation methodologies.[4] Consequently, it would be premature and inappropriate at this time to identify a specific cost allocation methodology to apply to the fixed costs of the NOPS alternatives in the reference and requested portfolios that ENO has presented.

Q. PENDING THE COUNCIL DECISION IN THE COMBINED RATE CASE REGARDING COST ALLOCATION METHODOLOGIES, WHAT DO YOU CONSIDER TO BE A LOGICAL APPROACH TO ESTIMATE THE IMPACT FROM THE ALLOCATION OF PROJECT FIXED COSTS TO CUSTOMER CLASSES?

A. It has been several years since the Council's last examination of appropriate cost allocation methods and results to customer classes. In my opinion, the logical approach at this time for preparing an estimate of the ratepayer impact from the allocation of project fixed costs is to allocate them on customer class base rate revenues. This approach has been used to allocate the recent revenue adjustments of ENO's Formula Rate Plans, it represents a reasonable non-kWh related allocation of fixed cost recovery to use prior to the Combined Rate Case, and has been acceptable to some of the parties in

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[4] *See* Air Products Response to CNO 1-2: "Specifically, the preferred approach is to allocate these costs, along with any other relevant cost increases or decreases in a full base rate proceeding that is informed by an **appropriate** class cost of service study." (emphasis added.)

this Docket.[5] Using this cost allocation approach, Witness Watson will discuss the estimated allocated revenue requirements and ratepayer impacts of the NOPS projects.

IV. ENO'S PROPOSED REGULATORY APPROVAL PLAN

Q. PLEASE DESCRIBE THE COMPONENTS OF ENO'S PROPOSED REGULATORY APPROVAL PLAN.

A. ENO has requested approval of their proposed In-Service Cost Recovery Plan, related to timely recovery of NOPS non-fuel/fixed costs, that they propose would commence concurrent with the day on which the plant begins commercial operation. ENO's In-Service Cost Recovery Plan is based on several assumptions: (i) that ENO's anticipated Combined Rate Case will conclude prior to COD of each of the NOPS alternatives, and therefore timely recovery is precluded in the new rates; (ii) a full and fair opportunity to recover prudently incurred costs of the Project should therefore be accomplished with a contemporaneous exact cost recovery Rider; and (iii) ENO anticipates an FRP subsequent to the Combined Rate Case, in which ENO's initial year ROE evaluation would exclude the project costs and revenue recovered in its proposed Rider. ENO also requested that the operation and maintenance costs incurred under the project LTSA be recovered through the fuel adjustment clause.

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5 *See* Air Products Response to CNO 1-2: "In the absence of a class cost of service study, the appropriate approach would be to apply a uniform percentage factor to the base rate revenue of all customer classes." And: "Specifically, the preferred approach is to allocate these costs, along with any other relevant cost increases or decreases in a full base rate proceeding that is informed by an appropriate class cost of service study. Otherwise, allocation of these costs on class base rate revenues would be appropriate."

Q. PLEASE DESCRIBE THE PRINCIPAL REGULATORY ASSUMPTIONS OF ENO'S IN-SERVICE COST RECOVERY PLAN AS PROPOSED IN THE APPLICATION.

A. ENO expects that the Council will allow timely recovery of the NOPS costs, similar to Union Power Block 1 and the Ninemile 6 Purchased Power Agreement ("PPA"). Specifically, in its Application ENO expected NOPS to commence commercial operation in the second half of 2019, and ENO requested contemporaneous recovery of the NOPS non-fuel/capacity costs at that time through an exact cost recovery Rider similar to what the Council approved with the Ninemile 6 PPA Interim Rider and PPCACR Rider. ENO based its request for the exact cost recovery Rider on the expectation that expenses incurred with commercial operation would not be reflected in base rates at that time. ENO assumes that that Combined Rate Case described in the Algiers Transaction Agreement in Principle[6] will be completed by the second half of 2019 and that the recovery of capacity costs in the existing PPCACR Rider[7] will be realigned to combined ENO base rates at the effective date of the new rates. Thus ENO expects that a new Rider would be applicable to all customers, including Algiers, and would replace the existing PPCACR Rider as the rate mechanism to recover NOPS non-fuel costs,[8]

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[6] The Agreement in Principle, Council Docket No. UD-14-02, approved in Resolution No. R-15-194, at P 8.

[7] The existing PPCACR Rider recovers non-fuel costs of both Union Power Block 1 and Ninemile 6 PPA.

[8] Supplemental and Amending Direct Testimony of Orlando Todd, at 6. Witness Todd stated that PPCACR Rider would be modified for non-fuel cost recovery of the NOPS alternative, or a similar exact cost recovery Rider would be used. Also "Following the initial twelve-month's dollar-for-dollar recovery, the Project's non-fuel revenue requirement would be realigned so as to be recovered through the FRP Rate Adjustment." No specifics were provided regarding how the PPCACR Rider would be modified for non-fuel cost recovery.

including a return component based on the return on equity resulting from the Combined Rate Case, as well as ENO's actual capital structure. Finally, ENO makes the regulatory assumption that the Council will approve an FRP for the annual periods following the Combined Rate Case.

Q. WHICH OF ENO REGULATORY ASSUMPTIONS DO YOU CONSIDER REASONABLE?

A. I agree that the cost recovery for the approved project should be based on the return on equity resulting from the Combined Rate Case, as well as ENO's actual capital structure reflected in any FRP revenue adjustments, as reasonably applied. The project's revenue requirement should be applicable to all customers, including Algiers. However, I note that ENO's Application does not address how the non-fuel revenue requirement should be allocated to all customer classes.

Q. HOW DID ENO ASSUME THAT THEIR PROPOSED EXACT COST RECOVERY RIDER WOULD BE IMPLEMENTED IF THE COUNCIL APPROVED A FORMULA RATE PLAN?

A. Since ENO assumes that their proposed NOPS Rider would be implemented soon after the time that the Council concludes the Combined Rate Case, the Rider would be based on the ROE resulting from the Combined Rate Case as well as ENO's actual capital structure at the time NOPS would commence commercial operation. And assuming an

FRP is approved to commence in 2020,[9] ENO expects that the FRP would be structured with a bandwidth formula, similar to the FRP ensuing from ENO's previous rate case. ENO proposes that a NOPS exact cost recovery Rider would be an interim step, with realignment into the first FRP rate adjustment in 2020. Of particular note, ENO also expects that realignment to be outside the FRP ROE bandwidth formula with the first FRP rate adjustment in 2020, but included in the FRP ROE bandwidth formula in the 2021 FRP rate adjustment.

V. ISSUES WITH ENO'S PROPOSED COST RECOVERY RIDER

Q. DO YOU HAVE ANY CONCERNS WITH ENO'S PROPOSAL TO USE A COST RECOVERY RIDER TO RECOVER THE NON-FUEL PROJECT COSTS?

A. Yes. I disagree with ENO's assumptions regarding their proposed Rider. While there are well established regulatory principles stating that ENO should have a full and fair opportunity to recover prudently incurred costs of whatever project and level of capital spending that the Council might approve, that "fair opportunity" should not be limited to or strictly defined as a contemporaneous exact cost recovery rate mechanism. Furthermore, I consider the use of the proposed Rider in this instance to recover the project's fixed/non-fuel costs to be single issue ratemaking.

Q. WHAT IS SINGLE ISSUE RATEMAKING?

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[9] If revised rates from the Combined Rate Case, filed in 2018, were effective in 2019, an FRP, if approved, would likely be filed in the first half of 2020, with the FRP rate adjustment effective in the second half of 2020.

A. Single issue ratemaking is a departure from the accepted regulatory ratemaking principle that the design of rates should generally be based on a utility's overall costs and risks.[10] The concern is clearly summarized by the Supreme Court of Louisiana: "Single-issue ratemaking occurs when a utility's rates are altered on the basis of only one of the numerous factors that are considered when determining the revenue requirements of a regulated utility."[11] I believe that when particular portions of a utility's revenue requirement, notably significant fixed costs, are considered for recovery in isolation from the utility's total costs and revenues, there is a concern of single issue ratemaking.

Q. WHY IS SINGLE ISSUE RATEMAKING REGARDED WITH SO MUCH CONCERN WHEN CONSIDERING COST RECOVERY ALTERNATIVES?

A. A generally accepted regulatory ratemaking principle is that a utility's revenue requirement should be based on the utility's overall costs, and all cost recovery rate mechanisms should derive from that basis. Designing rates from a separate or singular cost analysis may not include the overall impacts considered in a utility's total revenue requirement by not reflecting offsetting changes from other areas of the utility's operations. There is an additional concern in that single issue ratemaking in terms of the

[10] The Code of the City of New Orleans, Louisiana (section 158-134) reflects this principle by requiring a total company and jurisdictional income statement part of rate case applications, including a forward looking test period. Also, the Louisiana Supreme Court has stated: "The general approach of a regulatory agency in determining whether an existing rate structure is producing inadequate or excessive revenues is well established. The agency first selects a 'test year,' normally the most recent annual period for which complete financial data are available, and calculates the utility's revenues, expenses and investments during the test period." (*S. Central Bell Telephone Co. v. La. Pub. Serv. Comm'n*, 352 So. 2d 964, 967 (La. 1977)).

[11] *Entergy Louisiana, LLC v. La. Pub. Serv. Comm'n*, , 990 So. 2d 716, 727 (La. 2008).

proposed Rider may reduce the incentive to control costs to the extent that it guarantees cost recovery without a complete examination of total utility costs.

Q. HOW HAVE THESE CONCERNS BEEN RECOGNIZED IN OTHER REGULATORY JURISDICTIONS?

A. Single-issue ratemaking is generally considered to be impermissible with few exceptions. For example, Missouri statutes defining the Public Service Commission duties has been found to mean that the Commission's determination of proper rates must be based on all relevant factors rather than on consideration of any single factor: "[T]he phrase 'among other things' clearly denotes that 'proper determination' of such charges is to be based upon all relevant factors."[12] The rationale underlying the rule is that a rate based upon the fluctuation of only a single cost factor may overlook savings elsewhere, leading to rates that are not just and reasonable.[13]

Similar concerns regarding single issue ratemaking have been expressed in several Pennsylvania cases: "This prohibition is based on the rate maker's obligation to consider all of a utility's revenues and costs in the balancing process to achieve just and reasonable rates. Moreover, review of expense items in isolation could result in

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12 *State ex rel. Missouri Water Co. v. Pub. Serv. Comm'n of the State of Missouri*, 308 S.W. 2d 704, 718-719 (Mo. 1957), *quoting N.Y. Telephone Co. v. N.Y. Pub. Serv. Comm'n*, 132 N.E. 2d 847, 850 (1956).

13 *State ex rel. Midwest Gas Users' Ass'n v. Pub. Serv. Comm'n of the State of Missouri*, 976 S.W. 2d 470, 479 (Mo. App., W.D. 1998). The Court stated that the rule against single-issue ratemaking was a method of recognizing that the revenue formula in a given rate case was designed to determine the revenue requirement based on aggregate costs and demand to the utility. The rule against single-issue ratemaking was necessary because of the impropriety of considering changes to components of the revenue requirement without considering corresponding changes that would result from adjustments to the various elements of the rate formula.

confiscatory rates."[14] These concerns were specifically related to ratemaking circumventing the process of establishing rates through a general base rate proceeding including the effects on various rate classes: "[s]ingle-issue ratemaking occurs when a utility attempts to recover a line item that is traditionally requested in a general base rate proceeding."[15] And "[s]ingle issue ratemaking is similar to retroactive ratemaking and, in general, is prohibited if it impacts on a matter that is normally considered in a base rate case."[16]

The Oklahoma Commission cited state statutes in addressing its concerns regarding single issue ratemaking in a recent case:[17] "The relief requested by PSO would require the Commission to engage in single issue ratemaking. Such single issue ratemaking would result in rates that are not reasonable or just to PSO's ratepayers, in violation of Okla. Const. Art. 9, §18. Under Oklahoma law, the rates of a public utility are determined by examining the assets and expenses of the utility in conducting its service to the public in the aggregate.[18] Thus, although the Oklahoma Supreme Court has not

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[14] *Nt'l Fuel Gas Dist. Corp. v. Pennsylvania Pub. Util. Comm'n*, 464 A.2d 546, 567 (Pa. Cmwlth. Ct. 1983).

[15] *Pennsylvania Indus. Energy Coalition v. Pennsylvania Pub. Util. Comm'n*, 653 A.2d 1336 (Pa. Cmwlth. 1995) (PIEC). [Equitable Gas Company, LLC R-2012-2304727 R-2012-2304731, *et al*. PUR4th — Pennsylvania Public Utility Commission (Dec. 20, 2012)].

[16] *Pennsylvania Indus. Energy Coalition v. Pennsylvania Pub. Util. Comm'n*, 653 A.2d at 1350. And in a similar case: "If PGW needs additional revenues to meet its obligations, we must review Company expenses, revenues and savings as a whole. By examining the larger picture, we also can consider the effect on the various rate classes. [Pennsylvania Public Utility Commission v. Philadelphia Gas Works, R-00049157, P-00042090 , PUR4th —, Pennsylvania Public Utility Commission, July 8, 2004.

[17] Public Service Company of Oklahoma, Cause No. PUD 201200079, Order No. 631897, 316 PUR4th 414, Oklahoma Corporation Commission, October 16, 2014.

[18] See Turpen v. Oklahoma Corporation Commission, 1988 OK 126, 769 P.2d 1309, 1316, n. 7; State ex rel. Cartwright v. Oklahoma Natural Gas Co., 1982 OK 11, 640 P.2d 1341, 1349.

necessarily used the words 'single issue ratemaking,' such single issue ratemaking is generally prohibited, with certain statutory exceptions (none of which address earning returns or profits in the case of purchased power). The Commission, in determining a reasonable rate of return, must look at all factors. Otherwise, it would be pursuing impermissible single issue ratemaking."[19]

Q. WHAT EXCEPTIONS TO SINGLE ISSUE RATEMAKING HAVE BEEN NOTED IN OTHER JURISDICTIONS?

A. A relevant Illinois case established that rider recovery is exempt from the prohibition against single-issue ratemaking when there is adequate justification or need for rider recovery — such as alleviating the burden imposed upon a utility in meeting **unexpected**, **volatile or fluctuating** expenses.[20]

The Colorado Public Utilities Commission made several qualifications in its acceptance of an interim Rider.[21] Although, Public Service Colorado admitted that its application for a PCCA (Purchased capacity cost adjustment rider) may be viewed as single-issue ratemaking, ENO was not able to time its purchased capacity obligation with its rate case filing, and another rate case filing was not expected for several years. The Commission stated: "We agree that single-issue ratemaking should be approached with hesitancy. However, we agree that, in this particular case, administrative efficiency favors a cost

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[19] *Id*.

[20] *A. Finkl & Sons Co. v. Illinois Commerce Comm'n*, 250 Ill. App. 3d 317 (1st Dist. 1993).

[21] Public Service Company of Colorado, Docket No. 03A-436E, Decision No. C04-476, 234 PUR4th 329, Colorado Public Utilities Commission, May 10, 2004.

recovery mechanism. We find that it would be impractical to conduct another rate case in the near future to allow Public Service to recover capacity costs that the Commission has ordered it to incur."[22] In this case since the unexpected costs were not considered in the recently completed rate case, the Commission reluctantly allowed the interim rider under the stipulation that it be included in the utility's existing earnings test mechanism. I conclude that the few exceptions to single issue ratemaking should be limited to unexpected costs that cannot be evaluated in a current or anticipated rate case, or expenses that are volatile or fluctuating by nature.

Q. IS THE COUNCIL'S APPROVAL OF ENO'S PURCHASED POWER AND CAPACITY ACQUISITION COST RECOVERY RIDER THE BASIS FOR AN EXCEPTION TO SINGLE ISSUE RATEMAKING WITH RESPECT TO ENO'S PROPOSED RIDER?

A. No. The Council allowing special cost recovery with the PPCACR Rider is based on a compromise[23] negotiated settlement to Council Docket No. UD-14-02, and is non-precedential.[24] The Council is not required to give the PPCACR Rider any weight in its consideration of the appropriate treatment for project fixed costs recovery in the instant docket.

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22 *Id.*

23 Resolution No. R-15-194, paragraph 4 at page 5, and paragraph 3 at page 14.

24 *Id.*at paragraph 6 at page 15.

Q. DO YOU BELIEVE THAT ANY EXCEPTIONS SHOULD BE MADE TO THE SINGLE ISSUE RATEMAKING EXEMPTION WITH REGARD TO ENO'S PROPOSED COST RECOVERY RIDER?

A. No. Regarding cost recovery of the alternatives' project costs, there is no burden imposed upon ENO in meeting unexpected, volatile or fluctuating expenses that would require an exception to the exemption for single issue ratemaking. ENO will have a full and fair opportunity to recover prudently incurred project costs without the need or requirement of a cost recovery Rider. As I will discuss further in my testimony, the Combined Rate Case anticipated to be filed by mid-2018, together with subsequent annual reviews for revenue adjustments (via an FRP or full decoupling mechanism), will provide the Council with an examination of total utility fixed costs, including pro-forma adjustments and ratemaking options regarding prospective rates for the cost recovery periods of the NOPS alternatives.

Q. HAS ENO DEMONSTRATED THAT IT WILL BE SUBJECT TO ANY ADVERSE FINANCIAL CONSEQUENCES IF IT DOES NOT RECEIVE RECOVERY OF THE NOPS PROJECT FIXED COSTS THROUGH AN EXACT COST RECOVERY RIDER?

A. No. ENO has not demonstrated that its financial stability and credit ratings would be adversely affected if the opportunity for cost recovery were provided by other than a contemporaneous exact cost recovery Rider. In discovery responses, ENO could only provide general statements without any credible financial analysis to support any showing of financial harm if their proposed cost recovery Rider was not implemented.[25] The opportunity for timely NOPS cost recovery would also be increased with a prospective two-step rate increase and the FRP or full decoupling revenue adjustments in the next annual period of 2020.

VI. ACCEPTABLE APPROACH TO NOPS PROJECT COST RECOVERY

Q. RECOGNIZING THE CONCERNS WITH ENO'S PROPOSED RIDER, WHAT DO YOU CONSIDER AS AN ACCEPTABLE COST RECOVERY TREATMENT FOR NOPS PROJECT FIXED COSTS?

A. The cost recovery of NOPS project fixed costs can be evaluated during the Council's consideration of the Combined Rate Case which is expected to conclude by mid-year 2019, and prospective cost recovery can be accommodated through forward-looking rates. Regarding the transmission alternative, no contemporaneous rider as proposed by ENO would be required, as cost recovery would be accomplished through the annual revenue adjustments anticipated for the next several years following the Combined Rate Case.[26]

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[25] Refer to responses to CNO 7-2, 8-15, 9-1, and 10-20. ENO's general statements in these responses regarding "significant financial risk" if their proposed Rider is not implemented assume either (i) that the Council would not permit contemporaneous cost recovery, or (ii) that their proposed Rider is the only rate mechanism available to provide contemporaneous cost recovery.

[26] Refer to the Supplemental and Amending Direct Testimony of Charles W. Long, page 11, Table 1, "No NOPS" Transmission Upgrades, which shows several transmission projects with a total project cost of $57.1 million and a "Need-by date" of summer 2021. As indicated later in this testimony, the annual revenue adjustments anticipated from an FRP or full decoupling mechanism would include the fixed cost recovery of the transmission alternative.

Q. WHY DO YOU BELIEVE THAT THE NOPS PROJECT FIXED COST RECOVERY SHOULD BE EVALUATED IN A FULL RATE CASE?

A. A full rate case provides the Council and all Stakeholders the appropriate regulatory forum to completely evaluate all significant changes to ENO's total revenue requirements, including major capacity additions. I recommend that the Council adhere to that sound regulatory practice with regard to the NOPS project costs of the several alternatives. As I noted previously, riders have only been approved for recovery of substantial non-fuel/fixed costs when a full rate case was not imminent or expected to be completed in a reasonable time relative to the initial incurrence of those substantial costs. However, based on the Application and subsequent discovery responses, the targeted commercial operation date of either NOPS alternative would be relatively close to the effective date of revised rates from the Combined Rate Case and the subsequent annual revenue adjustments. Furthermore, in past rate actions ENO has not hesitated to support a comprehensive forward-looking approach toward cost recovery by including several pro-forma adjustments applicable to the prospective period(s) in which new rates would be effective. In addition, step or staged rate increases to accommodate separate timing with respect to increased costs of service have been adopted in other regulatory jurisdictions.[27] After the revenue requirement impacts of the NOPS alternative would be completely vetted in the Combined Rate Case relative to total ENO operations, including the important details involving allocated cost recovery for each of the customer classes and rate design, the Council can decide on the timing of any step rate changes for NOPS cost recovery that may be appropriate to correlate with NOPS commercial operation.

Q. DO YOU HAVE ANY ADDITIONAL OBSERVATIONS REGARDING THE PROSPECTIVE EVALUATION AND RECOVERY OF NOPS PROJECT FIXED COSTS?

A. Yes. If the Council does not approve an FRP in the Combined Rate Case, an annual evaluation of NOPS cost recovery would be provided through an ENO full revenue decoupling mechanism approved by the Council. In Resolution No. R-16-103, the Council directed ENO to include in its next base rate case filing a proposal for a three year full decoupling mechanism, with or without an FRP, to begin with the implementation of rate changes arising from the Combined Rate Case. If an FRP is not adopted in the Combined Rate Case, the target revenue requirement for annual full decoupling revenue adjustments could include significant changes to fixed costs, such as the addition of new generating capacity. This requirement for ENO to propose a three

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[27] Authority for the Florida PSC to approve prospective rate increases has been expressly recognized by the *Florida Supreme Court in Floridians United for Safe Energy. Inc. v. Pub. Serv. Comm'n*, 475 So. 2d 241 (Fla. 1985); Fla PSC Order No. PSC-09-0283-FOF-EI, Tampa Elec. Co. 21st day of August, 2009; NH.PUC*12/30/08*[PURbase 163770]*— PUR4th where NH PUC ordered three stage rate increases to accommodate specific projected increased levels of capital investment in the utility; WI.PSC*08/15/13*[PURbase 176696]*— Two step rate increase related to specific increased projected levels of capital investment; and Application No. 58331 (1979) before CA PUC.

year decoupling mechanism without an FRP represents an additional opportunity for ENO's recovery of project fixed costs.

Q. PLEASE SUMMARIZE AN ESTIMATED TIMEATABLE SHOWING HOW YOUR RECOMMENDED TWO STEP RATE ADJUSTMENT MIGHT BE IMPLEMENTED RELATIVE TO AN FRP OR DECOUPLING MECHANISM SUBSEQUENT TO THE COMBINED RATE CASE.

A. If an FRP is approved by the Council, the first step would occur with new rates anticipated to be effective by August 1, 2019. The second step would occur with the COD of the NOPS project,[28] which is anticipated to be no sooner than 2020. Depending on the structure of an approved FRP, the FRP would be filed by May 31, 2020, and an adjustment to base rate revenue (including the two step increase, depending on the timing of a COD in 2020) could occur in October 2020. The first FRP adjustment would be based on a 2019 test year and customer class allocations from the Combined Rate Case including pro-forma costs of the NOPS project. If an FRP is not approved, the second step increase would still occur with the COD of the NOPS project. The stand-alone full decoupling adjustment would be filed annually by May 31, 2020, maintaining the total utility fixed cost revenue requirement approved in the Combined Rate Case with the limited exception that the revenue requirement be reset with a substantial change to the fixed cost of service, such as the addition of new generating capacity (NOPS).

[28] Per ENO response to CNO 12-14: "The current schedule would guarantee commercial operation in early January 2020 if a notice to proceed is granted to the EPC contractor by March 1, 2018."

Resolution R-16-103 provides 60 days for responses by interested parties and a rate change implementation date of the first billing cycle of the month following Council approval. In either of the FRP and stand-alone decoupling cases, the two step rate increase would apply with the project COD, and there would be three years of revenue adjustments based on the project fixed costs updated in each test period.

VII. ENO PROPOSAL TO RECOVER PROJECT FIXED COSTS OUTSIDE-THE-ROE BANDWIDTH IN AN FRP.

Q. ASSUMING THAT THE COUNCIL APPROVES AN ANNUAL FRP ADJUSTMENT AFTER THE COMBINED RATE CASE, DO YOU AGREE WITH ENO'S PROPOSAL THAT REALIGNMENT OF NOPS PROJECT FIXED COSTS INTO THE FIRST FRP RATE ADJUSTMENT SHOULD BE OUTSIDE AN ROE BANDWIDTH FORMULA?

A. No. I do not concur that the cost recovery for a capital project approved by the Council should be evaluated outside of an FRP ROE bandwidth formula for its initial year. An FRP revenue adjustment, determined relative to a Council approved ROE, should be based on the revenue requirement related to all fixed costs, including first year project fixed costs. If NOPS were approved for commercial operation as soon as late 2019, under ENO's FRP bandwidth proposal it would be approximately two years later in October 2021, with the second FRP revenue adjustment, that rates would reflect the NOPS revenue requirement evaluated in terms of ENO's approved ROE. The issue of an FRP revenue adjustment based on an ROE evaluation of all fixed costs and revenues in the test period is similar to the concerns that were summarized previously relative to single issue ratemaking. As an example, in a recent case, the Colorado Public Utilities Commission held that the costs recovered through a Purchased Capacity Adjustment Rider should be included in the utility's existing earnings test mechanism, with overearnings returned to customers based on the current sharing formula.[29]

VIII. <u>LTSA COST RECOVERY</u>

Q. WHAT IS YOUR OPINION REGARDING THE COST RECOVERY AND RATE TREATMENT OF LTSA COSTS?

A. The LTSA costs are payments for major maintenance activities, consisting of a fixed contract portion and other payments varying somewhat based on project utilization such as unit starts and run-time. LTSAs have been used for other Entergy generation projects and will likely be applicable to both NOPS generation alternatives. I concur with Witness Rogers Testimony in Docket No. UD-15-01[30] that LTSA costs are expected to be regularly occurring and predictable costs for major maintenance. While the LTSA has some variance in quarterly and annual costs as in many O&M accounts, these long term maintenance costs are predominately fixed costs and have been recovered in other regulatory jurisdictions as such with fixed cost allocations and cost recovery mechanisms

[29] Public Service Company of Colorado, Docket No. 03A-436E, Decision No. C04-476, 234 PUR4th 329, Colorado Public Utilities Commission (May 10, 2004).

[30] ENO's Application for Approval to Purchase Power Block 1 of Union Power Station, Docket No. UD-15-01, Direct Testimony of Joseph W. Rogers, at 19, and Supplemental Direct Testimony of Joseph W. Rogers, at 18-20.

– not with fuel as a variable cost. LTSA costs do not vary to the extent of the unpredictability experienced with fuel expense; rather, LTSA costs have the same characteristic occurrence as plant maintenance O&M expenses which are treated under fixed cost recovery. Therefore, I recommend that LTSA costs be recovered using the same methodology to recover all other NOPS fixed/non-fuel costs.

Q. HAVE YOU REVIEWED THE TREATMENT OF LTSA COST RECOVERY IN OTHER REGULATORY JURISDICTIONS?

A. Yes. In 2015, the Arkansas Public Service Commission ("APSC") followed state Commission precedent regarding earlier acquisitions in which LTSA costs were recovered consistent with the fixed cost recovery of the generating unit. Specifically the APSC pointed out that "the maintenance costs accompanying the acquisition of a major new generating asset generally belong in base rates and not in a rider dedicated to fuel cost recovery."[31] I also reviewed recent cases in Nevada and California where LTSA expenses were included in rates based on test period costs.[32]

Q. WHAT IS ENO'S PROPOSAL REGARDING RECOVERY OF LTSA COSTS?

A. ENO proposes that LTSA costs should be considered solely as variable costs and be recovered entirely in the fuel adjustment clause ("FAC"). ENO estimates LTSA costs for

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31 Entergy Arkansas, Inc., Docket No. 14-118-U, Order No. 7, — PUR4th —, Arkansas Public Service Commission (Nov. 30, 2015(.

32 Nevada PSC, 12/23/11, PUR 173,500, Nevada Power Company, and CAPUC, 07/29/10, PUR 169775, PG&E

the initial year of NOPS operation to be substantial costs of approximately $4.1 million,[33] so the methodology of allocating LTSA cost recovery must consider cost responsibility and fairness between customer classes. Since the FAC cost recovery is based on kWh sales, LTSA cost recovery through the FAC, under the assumption of LTSA costs being solely variable costs, results in a greater relative impact to high load factor/high use customers.

Q. CAN YOU DEMONSTRATE THE COST IMPACT ON CUSTOMER CLASSES FROM DIFFERENT COST ALLOCATION METHODOLOGIES BY USING FIXED COSTS THAT ARE CURRENTLY BEING RECOVERED IN ENO'S FAC?

A. Yes. Table 1 below is a summary of results for a recent 12 month period of fixed costs being recovered for ENO-Legacy in the FAC. The first line represents the recovery of those fixed costs from customer classes using the kWh allocation basis of the FAC Rider. The second line of Table 1 represents the recovery of these same fixed costs from customer classes using base rate revenues as an interim cost allocation method pending the Council's evaluations in the Combined rate case. The third line of Table 1 confirms that there is a substantial impact among customer classes related to the allocation methodology used in the recovery of fixed costs. Fairness among customer classes is maintained by a cost recovery treatment that is based on cost incurrence. The

[33] Direct Testimony of Robert A. Breedlove, Table 1, page 6.

indiscriminate use of the volumetric recovery of costs through the FAC should be avoided.

Table 1 **ENO - Legacy** **Fuel Adjustment Clause Fixed Costs Recovery** **12 Months Ending October 2017**					
	Total Fixed Cost	**Residential**	**Small Commercial**	**Large Commercial**	**Other**
Fixed Costs - kWh Allocation[1]	$66,483,984[3]	$24,377,899	$9,984,458	$31,126,196	$995,432
Fixed Costs - Base Rate Revenue Allocation[2]	$66,483,984[3]	$28,356,039	$11,397,220	$25,068,633	$1,662,091
Difference	-	***$3,978,141***	***$1,412,762***	***$(6,057,562)***	***$666,659***

[1]Allocated Based on 2016 FERC Form 1 MWh's Sold
[2]Allocated Based on 2016 FERC Form 1 Base Rate Revenues
[3]Total Fixed Costs Taken From the 12 Month Total of Fuel Adjustment Clause, Legacy ENO Geographic- Specific Adjustments. Page "4 Geographic - Specific Legacy ENO Adjustments" Line 15.

IX. COMPARISON OF DSM ANNUAL PEAK REDUCTIONS USED IN ENO ANALYSES

Q. PLEASE SUMMARIZE THE DIFFERENT SETS OF DSM REDUCTIONS AT THE ANNUAL ENO SYSTEM PEAKS THAT WERE USED IN ENO ANALYSES.

A. ENO used one set of estimated DSM peak reductions for the economic analysis of their three Reference Case portfolios, which was intended to reflect current levels of DSM peak reduction with no projected DSM program increases.[34] A second set of estimated

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[34] Supplemental Direct Testimony of Seth E. Cureington, 27.

DSM peak reductions was constructed to reflect the Council policy regarding a DSM goal to be incorporated with the implementation of prospective ENO DSM programs, and was used in the economic analysis of their four Requested Case portfolios. A third set of DSM peak reductions for specific forecasted years was included in ENO's transmission analyses, as discussed in the testimony of Witness Movish. The third set of DSM reductions was also intended to reflect the Council policy regarding a DSM goal, but the DSM reduction values used in that analysis were noticeably less than the corresponding annual values of the second set referenced above.

Q. DID YOU PREPARE A COMPARISON BY YEAR OF THESE THREE SETS OF DSM PEAK REDUCTIONS USED BY ENO?

A. Yes. Table 2 below shows a year by year comparison of the estimated MW reduction to the annual system peak for each of the three sets I referenced above.

Table 2
Annual DSM System Peak Reduction
2017-2036
MW; Includes Transmission & Distribution Losses

Year	Reference Case[1]	Councils 2% DSM Goal[2]	Transmission Analysis[3]
2017	[redacted]		
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
2035			
2036			

[1]Taken from ENO's Response to Discovery Question ADV 7-3, File TC-UD1602-00ADV007-N003-006 (b)BP17U ENOI Existing DSM Analysis_HSPM
[2]Calculated from ENO's Response to Discovery Question ADV 7-3, File BP17U_ENOI_NonCoinPks_TC_2%DSMScenario_c_HSPM
[3]Taken from ENO's Response to Discovery Question ADV 13-1 HSPM

Q. WHAT ASSUMPTIONS DID ENO USE IN DEVELOPING THESE THREE SETS OF ESTIMATED DSM PEAK MW REDUCTIONS?

A. For ENO's economic analysis of its three Reference Cases presented in Exhibit SEC-12, ENO assumed a "continuation of the Energy Smart program."[35] Specifically, ENO used the Energy Smart kWh savings for program year 6 (12 months ended March 2017) and assumed that that level of incremental annual kWh savings would continue for the 20-year analysis period. For the four Requested Cases, ENO assumed a 0.2% increase in DSM kWh savings relative to sales each year starting in 2019 until attaining an annual incremental DSM savings of 2% of sales. For the transmission analyses performed by ENO, no additional work papers were provided to explain why the projected DSM peak reductions for the specific years of the analysis (column 3 of Table 2) differed from those previously provided by ENO related to the Council policy (column 2 of Table 2).[36] An important assumption related to the values of Table 2 is that the system peak MW reductions indicated for all three sets of DSM impacts are calculated from annual energy efficiency kWh reductions; no demand response programs were included in the DSM system peak MW reductions.

Q. DID YOU REVIEW THE DEVELOPMENT OF ENO'S PROJECTED DSM REDUCTIONS IN ENO'S WORK PAPERS?

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35 Supplemental Direct Testimony of Seth E. Cureington, 27:2.

36 Workpapers to support the estimated DSM peak reductions used in ENO's transmission analysis were requested in CNO discovery set 15, but those work papers did not show why the DSM peak reduction values differ.

A. Yes. For the DSM reductions shown in Column 1 of Table 2 ("existing DSM"), ENO provided work papers in discovery,[37] which included the impact on ENO's system peak assuming that existing Energy Smart program levels of incremental annual kWh savings will be held constant at 2016 levels with prior years' program kWh benefits depreciated forward. ENO also provided hourly load profile data based on load research that was used to estimate the system peak MW reductions from the annual kWh savings. For the DSM peak reductions shown in Column 2 of Table 2 ("Council 2% policy DSM"), ENO provided additional work papers in discovery[38] which developed cumulative kWh annual energy efficiency program savings by year incorporating the Council policy based on a three-year running average of annual kWh sales. Hourly load profile data and transmission/distribution losses were then used to estimate the yearly reduction to ENO's system peak.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

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37 ENO response to CNO 7-3, "TC-UD1602-00ADV007-003_006(b)_BP17U_ENOI_Existing_DSM_Analysis_HSPM".

38 ENO response to CNO 10-15, "TC-UD1602-00ADV010-N015_(a)_(i)_BP17U ENOI Existing DSM Analysis_HSPM".

AFFIRMATION

STATE OF COLORADO)
)
COUNTY OF DENVER)

I, Victor M. Prep, am the person identified in the attached Testimony and such testimony was prepared by me or under my direct supervision; the answers and information set forth therein are true to the best of my knowledge and belief, and if asked the questions set forth therein, my answers thereto would, under oath, be the same.

Victor M. Prep

Subscribed and sworn to before me this 20th day of November, 2017.

Robin Marie Shaver LaBarge

NOTARY PUBLIC

ROBIN MARIE SHAVER-LaBARGE
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20064043695
MY COMMISSION EXPIRES APRIL 3, 2019