BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Merger of Westar Energy, Inc. and Great Plains Energy Incorporated.	**))))))**	**Docket No. 18-KCPE-095-MER**

DIRECT TESTIMONY

OF

GARRETT COLE

on Behalf of the Kansas Electric Power Cooperative, Inc.

PUBLIC VERSION

January 29, 2018

I. BACKGROUND AND INTRODUCTION

Q. Please state your name, business, title and business address.

A. My name is Garrett Cole. I am a Principal Consultant for GDS Associates, Inc. ("GDS"). My business address is 1850 Parkway Place, Suite 800, Marietta, Georgia 30067.

Q. Please state your qualifications.

A. I graduated from the Georgia Institute of Technology in Atlanta, Georgia with a Bachelor of Science degree in Industrial Engineering in August 2002 and a Master of Science degree in Industrial Engineering in May 2003. I graduated from Kennesaw State University with a Master of Business Administration degree in May 2006 and became a licensed Professional Engineer in the state of Georgia in December 2006. I have been employed by GDS since 2001, and I have over sixteen (16) years of experience in the power industry.

At GDS, I perform a wide variety of consulting services primarily for municipals, cooperatives and law firms with a focus on strategic power supply, resource procurement, and Independent System Operator ("ISO") and Regional Transmission Organization ("RTO") market planning and analysis. In addition to broad utility management advice, I have made significant contributions to clients in the following core responsibilities:

(i) Strategic Resource Planning: Development of power supply procurement, portfolio management and Integrated Resource Plans ("IRP") in structured and unstructured markets and Balancing Authorities, including ERCOT, MISO, New England ISO, PJM, SPP, Duke Energy Carolinas, Entergy Arkansas, Florida Power & Light, Southern Company and Southwestern Power Administration.

(ii) Long-Term Resource Review: Performance of economic feasibility analyses, valuations and economic dispatch modeling to advise clients on participation in long-term (10-40 years in term) purchased power contracts and/or ownership interests in biomass, coal, natural gas-fired combined cycle and combustion turbines, hydroelectric, nuclear, solar and wind generation units.

(iii) Regulatory Planning: Participation in RTO stakeholder group representation, integration of generation and load into RTOs and review of statewide and Federal Energy Regulatory Commission ("FERC") issues.

(iv) Forecasting & Rates: Development of financial, wholesale power cost and annual operating budget forecasts.

(v) Risk Management: Risk modeling and development of risk management policies and procedures for boards of directors, city councils or city and state utility commissions and their staffs.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Kansas Electric Power Cooperative, Inc. ("KEPCo").

Q. What is the purpose of your testimony?

A. On August 25, 2017, Great Plains Energy, Kansas City Power & Light Company ("KCP&L"), and Westar Energy, Inc. ("Westar") submitted an application for approval of the merger ("Merger") of Westar and Great Plains Energy, the parent company of KCP&L (collectively, the "Applicants"). The Applicants have produced in discovery in this proceeding an IRP as ostensible support for the $55.4 million of Merger-related savings that Applicants claim they will realize over the first five years after the Merger closes due to accelerating the retirement of Westar units. My testimony will address whether the IRP is a reasonable, robust, reliable and credible source of support for Applicants' purported Merger-related savings.

Preliminarily, I note that Applicants focus on the claimed savings from the accelerated retirement of Westar generation, but they effectively ignore the risks. First, following the accelerated retirement of 777 MW of coal and gas-fired Westar generating capacity, in addition to other Great Plains Energy retirements, Applicants' resource plan substantively relies upon new and existing Demand-Side Management ("DSM") programs to continue to meet the SPP capacity reserve margin requirements. The resource plan includes approximately 700 MW of new DSM, over and above existing DSM programs, to be developed over a 7-year period (2017-2024). Their plans to significantly rely upon DSM programs are incomplete and fraught with much uncertainty as it relates to achieving Applicants' stated forecasts.

Second, there is a real opportunity cost to be paid with the accelerated retirement of the Westar generating capacity, as it will result in a loss of power supply flexibility and agility to react to changing conditions or failed assumptions. Once the generation is retired, Applicants are committed on a path of new spending to replace that capacity if outcomes differ to those assumed in the Applicants' resource plan. For example, in attempting to justify the development of approximately 700 MW of DSM in 7 years to replace 777 MW of Westar capacity to be retired on an accelerated basis, Applicants use the cost of a new combustion turbine ("CT") as the Avoided Capacity Cost. If the DSM targets are not met because, for example, the Commission adheres to its recent precedent and rejects the CT-based Avoided Capacity Cost for an avoided cost predicated on the cost of excess capacity in the Southwest Power Pool ("SPP") market, Applicants, absent Commission oversight, will likely build new generating capacity. In contrast, if some or all the Westar capacity slated for early retirement were retained in service, Applicants would have the flexibility to react to such an event in an organized and thorough manner with an opportunity to fully evaluate comparable economic alternatives without necessarily incurring the cost of new generating capacity. These and the several other factors I discuss in this testimony must be carefully evaluated before Applicants are permitted to retire the Westar generating capacity.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring the exhibits listed below:

Table 1. List of Exhibits

Exhibit	**Title**
GC-1	Resume
GC-2	IRP Preferred Plan ARP 2017 IC6MD
GC-3	Conflicting DSM Forecasts
GC-4	Westar DSM Forecast KS Regulatory Risk Factors (CONFIDENTIAL)

II. OVERVIEW AND BACKGROUND

Q. Please describe KEPCo's relationship to the Applicants.

A. KEPCo is a non-profit generation and transmission cooperative engaged in the business of providing electric power and energy to its 19 member distribution cooperatives in the State of Kansas, which in turn serve approximately 300,000 consumer members. KEPCo is a transmission-dependent cooperative utility relying upon service over the transmission systems of, among others, Westar, and its wholly-owned subsidiary Kansas Gas & Electric Company (referred to herein as "Westar") and the transmission system of KCP&L under the SPP Open Access Transmission Tariff ("OATT").

KEPCo manages its power supply requirements through (1) co-ownership of the Wolf Creek Generating Station with KCP&L and Westar, (2) co-ownership of Iatan Generation Station Unit 2 with KCP&L, Missouri Joint Municipal Electric Utility Commission ("MJMEUC"), and Empire District Electric Company ("EDE"), (3) 13 MW and 100 MW of hydroelectric-generated power from the Western Area Power Administration and Southwestern Power Administration, respectively; (4) power purchases of approximately 46 MW and 14 MW pursuant to agreements with Sunflower Electric Power Corporation, Inc., and (5) a significant amount of its power supply to meet its remaining requirements under a long-term, cost-based formula rate purchased power agreement with Westar (referred to herein as the "GFR Agreement").

Therefore, KEPCo, its cooperative members, and its members' retail members have a significant interest in the proposed merger, which is closely aligned with the interests of the Kansas retail rate customers of the Applicants, as all parties rely upon the Applicants for transmission service and energy requirements.

Q. Please describe the basic facts of this case as it refers to your testimony.

A. The Applicants' witness, Darrin R. Ives ("Ives"), outlines KCP&L's and KCP&L Greater Missouri Operations Company's ("GMO") plans to retire a number of generation units. In particular, he details in Table 2, page 19, that KCP&L plans to retire 340 MW of coal-fired generation and GMO plans to retire 463 MW of coal and 97 MW of gas-fired units.

In addition to these retirements, witness Ives claims the Merger will facilitate the accelerated retirement of a number of Westar generation resources. The resources in question consist of 70 MW of coal-fired generation and 707 MW of gas-fired generation.[1] He states that, "Prior to the Merger, Westar planned to retire five generating units between 2023 and 2028"[2] and that the Merger will allow these retirements to take place "in a range of 5-10 years earlier."[3]

Regarding the KCP&L and GMO retirements, Mr. Ives states, "These retirement dates will not change due to the Merger and are not included in the efficiencies presented as Merger savings."[4]. However, with respect to the Westar retirements, witness Ives states, "The Merger-related savings from accelerating the retirements of the Westar units are forecast to be $55.4 million over the first five years after the Merger closes. As these savings are significantly enabled by the Merger, the Applicants included them in their calculation of Merger savings."[5]

Q. How have the Applicants supported the decision to accelerate the retirement of the Westar units?

A. The Applicants rely upon a combined merged-company IRP completed in August 2017 ("2017 Combined IRP") and which was provided as a workpaper to the direct testimony of witness Ives.[6] The process undertaken, as described by witness Ives, "is similar to that which KCP&L conducts for its standalone IRP required to

[1] See Ives, direct testimony, Table 3, page 20.
[2] See *id.* at 19: 11-12.
[3] See *id.* at 20; 8-9.
[4] See *id.* at 20; 5-6.
[5] See *id.* at 21; 8-11.
[6] See Ives, workpaper, "2017 IC.pdf."

be filed in Missouri."[7] It should be noted that the provision of the Applicants' IRP to the Commission Staff is number 37 of its Proffered Merger Commitments and Conditions.[8]

Q. What does witness Ives conclude from the 2017 Combined IRP?

A. Witness Ives concludes that, "The analysis demonstrates that these Westar plants can be retired following the peak summer season in 2018 without negatively impacting cost to serve customers or Westar's ability to meet the reserve requirements established by SPP[.]"[9] Witness Ives further concludes "that the accelerated retirements result in the least cost option on a net present value of revenue requirements basis for customers over the 20-year planning horizon."[10]

Q. Do you agree that the analysis proves witness Ives's conclusion stated above?

A. No. The analysis presented is insufficient to substantiate this conclusion that the cost to serve customers will not be negatively impacted, that the SPP capacity reserve margin will be reliably met and that the accelerated retirements will result in the least cost option over a 20-year planning horizon. The 2017 Combined IRP is rigid, non-exhaustive and non-transparent. It only considered ONE possible retirement date for each Westar resource, failed to consider the Westar standalone retirement dates of the mid to late 2020s and does not discuss how the greater exposure to the SPP energy market will be mitigated.

[7] See Ives, direct testimony at 20:14 and 21:1.
[8] See *id.* at Exhibit DRI-1, page 12 of 13.
[9] *Id.* at 21:1-3.
[10] *Id.* at 21:4-5.

The resulting "Preferred Plan"[11] is unnecessarily inflexible and constrains future resource options through its combination of early Westar retirements and reliance on the necessary creation and aggressive implementation of new DSM programs. The IRP, as it stands, is not a reasonable basis to support the power supply course the Applicants propose to set the combined company on if the Merger is approved. In other words, the Applicants would set out to implement a power supply plan that is not supported by adequate or reliable analyses of that plan or the cost of its execution.

Q. Before discussing these concerns regarding the 2017 Combined IRP, please explain how your testimony relates to the Commission Merger Standards.

A. The testimony addresses matters that relate the principal focus of the Commission's Merger Standards, "whether the merger will promote the public interest," and specifically "(a)(iii) whether ratepayer benefits resulting from the transaction can be quantified[.]"[12] In my view, it is critical that the basis and justification supporting the identified benefits are demonstrated to be both reliable and credible and that the means to achieve the stated benefit is in the public interest.

In reference to this standard and the other standards, Witness Ives concludes that the "Applicants Amended Merger Agreement satisfies each of these

[11]Specifically, Alternative Resource Plan, IC6MD, as identified in Ives direct testimony workpaper "2017 IC.pdf" at pgs. 33, 36 and 49-51.
[12] Commission Order on Merger Standards at ¶ 5, In re Joint Application of Great Plains Energy Inc. and Westar Energy Inc. for Approval of the Acquisition of Westar Energy Inc., Docket Number 16-KCPE-593-ACQ (issued Aug. 9, 2016).

standards[.]"[13] However, I have a number of serious concerns, as my testimony will demonstrate, whether the resource plan put forward by the Applicants, and which was advanced by Applicants to substantiate the accelerated retirement of Westar units and the purported $55.4 million of Merger savings over five years, promotes the public interest. I conclude that the Applicants' IRP does not demonstrate "ratepayer benefits" in a reliable and credible manner, such that it promotes the public interest, and I recommend that, if the Commission decides to approve the Merger, it do so only after requiring a number of steps be taken to address these concerns.

III. INTEGRATED RESOURCE PLAN

Q. What is the purpose of an IRP?

A. IRPs are used to proactively identify a variety of known existing or potential new-build resource supply alternatives of varying fuel types, as well as a variety of DSM program alternatives, and comprehensively evaluate the effectiveness of those projects, given their various attributes, to meet load requirements in a manner that is reliable and at the lowest cost and risk. An IRP can also be used to identify areas of specific capacity and energy deficiency and the types of resources that would best meet those needs, in order to determine appropriate

[13] See Ives direct testimony at 31:8-9.

resource sizing and prevent mismatching of resources to expected load or to determine the most flexible resources that would best manage a variety of assumed scenarios with the lowest cost and risk balance. To accomplish this main IRP objective of lowest cost and lowest risk supply, the IRP process should be transparent to consider a full and exhaustive review of the economics and risks of all possible resource options and avoid being prematurely prescriptive of possible preferred solutions until the IRP has proven such narrowed alternatives.

Q. What was the objective of the 2017 Combined IRP?

A. As stated in the report itself, the analysis was "undertaken to determine the best economic path forward based upon 20-year net present value revenue requirement ("NPVRR")."[14]. The analysis evaluated the combined KCP&L, GMO and Westar supply portfolio "primarily to evaluate potential generating plant retirements."[15] Additionally, "The primary objective of the planning process is to identify the resource plan that minimizes the expected value of the NPVRR. However, there may be situations where a costlier plan is preferred in order to mitigate risk."[16]

Q. Please provide a brief description of the IRP process undertaken by the Applicants.

A. At the core of the IRP analysis are the Alternative Resource Plans ("ARP"). Sixteen different long-term resource plans were developed, which the report states "include combinations of different generating plant retirements, generating plant

[14] See Ives direct testimony workpaper "2017 IC.pdf" at p. 13, section 1.3 (quotation marks added to the term NPVRR).
[15] See *id.* at p. 17, section 1.4.
[16] See *id.* at p. 18, section 1.4.

additions and levels of Demand Side Management."[17] In determining the ARPs, an assessment of a number of supply-side technology candidates was undertaken. The NPVRR of each of these sixteen resource plans were evaluated over a 20-year horizon, *i.e.*, 2017 through 2036. The analysis incorporated the application of different critical uncertain factors, including scenarios of load growth, natural gas prices and CO2 credit prices, and each factor was allocated a weighted probability. The revenue requirement for the 16 ARPs was assessed under each critical uncertain factor scenario, and the results were ranked from least to most costly.

Q. Do you agree with witness Ives statement that this is a "robust IRP process"[18]?

A. No. The 2017 Combined IRP is rigid, non-exhaustive and non-transparent.

Q. Why do you consider the 2017 Combined IRP rigid?

A. While it is reasonable to determine preferred discrete scenarios to compare in IRP evaluations, there is very limited variability between the resource designs of the 16 ARPs. As noted earlier in my testimony, an IRP should seek to be exhaustive in its review of supply options to meet load requirements and not rigid or narrow in determining preferred scenarios for evaluation before comprehensively proving the economic and risk case for those same options. There are four key input assumption areas for each ARP defined in the 2017 Combined IRP, including its:

[17] See *id.* at pgs. 17-18, section 1.4.
[18] See Ives direct testimony at 35:22.

(1) DSM Penetration Level, (2) Supply-Side Resource Additions, (3) Unit Retirement Dates and (4) Renewables. The ARPs contain two sets of DSM assumptions. One can be considered a “Base Case” with combined KCP&L, GMO and Westar DSM of approximately 416 MW over the seven years from 2017-2024, and the other set has an “Additional DSM” assumption added of approximately 288 MW over that same period i.e., to increase DSM by approximately “700 MW over seven years” from 2017 to 2024. Please note that my testimony will later discuss the DSM assumptions in greater depth.

In determining the ARPs, the IRP pre-screened 25 candidate supply options, but importantly failed to include market-based supply options in its assessment, and “only a portion of the candidates were utilized in development of ARPs.”[19] The Applicants state that only a portion were utilized “Because some of the supply-side technology candidates were either considerably more costly in comparison to other technologies considered and/or permitting is currently expected to be extremely difficult to achieve.”[20] In response to a request for supporting workpapers used to substantiate this conclusion, the Applicants provided a file that details the costs of each candidate option[21], and stated, “This analysis determined which technologies were to be utilized in development of ARPs.” However, the provided analysis, which simply lists the cost of candidate options, is incomplete as it fails to demonstrate with analysis

[19] See Ives direct testimony workpaper “2017 IC.pdf” at p. 32, section 1.4.
[20] See *id.* at p. 32, section 1.4.
[21] See KCP&L discovery response to KEPCo 9-58 (CONFIDENTIAL).

"how" or "why" any of the candidate options are preferable to the others. The levelized cost per MWh is not enough information, alone, to distinguish between or substantiate a resource selection and its sizing. While Applicants review a variety of resources and corresponding costs in the 25 candidate options, all of these resources have different operating characteristics and, as a result, provide different energy amounts at different times to meet load requirements. It is a critical follow-up step to match resource capabilities at various capacity sizings and anticipated generation levels with Applicants' forecasted load levels to assemble the right types of resources to most efficiently meet Applicants' overall capacity and energy requirements. For example, Applicants are proposing the accelerated retirement of Westar units but do not evaluate the lost energy from these resources, the balance of energy that the merged entity units will be forecasted to provide or how the 25 candidate options might meet the remainder of Applicants' load requirements. Further, the supply options that might be available in the market to provide economical energy as compared to new-build are not considered. IRPs and resource plans using "best practices" would use a standard method to complete a screening evaluation of these 25 candidate supply options at varying energy levels and capacity sizings to determine resources that "best fit" load requirements. Common industry methodologies for such a screening might include the development of load duration curves, which match the type of resource to a corresponding portion of the load requirements, or economic dispatch models, which provide detailed forecasts for future generation dispatch – a critical issue for generation selection in the already low energy price environment in the SPP market. The Applicants do not demonstrate that this essential step was taken and move directly to the provision of 16 very specific ARPs.

Additionally, the IRP, and the ARPs that were developed, fail to comprehensively and holistically assess the Supply-Side Resource Additions candidate options together with the DSM options. Before selecting specific ARPs that include DSM, Applicants should evaluate the economics and characteristics of DSM measures as a resource right along-side the other 25 candidate options. The reasonableness of the DSM avoided energy should be assessed against other resources and not simply incorporated in the 16 ARPs because the potential to perform such DSM programs exists. In other words, Applicants pre-determined they were going to incorporate DSM in the 16 ARPs without studying such programs together with supply-side candidate options. Overall, the IRP's prescreening of the 25 candidate options for Supply-Side Resource Additions results in the establishment of a rigid and narrow set of ARPs and is insufficient to determine that the discrete selection of the 16 ARPs includes the best fit of lowest cost and lowest risk resources to meet Applicants' load requirements.

The retirement dates for the KCP&L and GMO units were fixed and did not change between ARPs. They reflect the retirements dates from the Preferred Plan determined in the 2017 Annual Updates for KCP&L and

GMO.[22] Only one ARP did not include the retirement of any Westar resource for the full assessment period of 2017 through 2036. The other ARPs included different combinations of the following Westar resources retiring: (a) Murray Gill 3&4, (b) Tecumseh 7, (c) Gordon Evans Steam 1&2 and (d) Lawrence 4&5.[23] However, only ONE retirement date was set for each respective Westar resource – December 31, 2018. There is no evidence provided that the 15 ARPs with the December 31, 2018 retirement date for Westar resources considered potentially later dates, such as the mid-to-late 2020s retirement dates currently planned by Westar,[24] to allow resource flexibility to manage risk or to evaluate whether it is specifically cost-prohibitive to retain these resources for a longer period.

When asked for the justification for only assessing the December 31, 2018 retirement date, Applicants' only response was the following: "Given results show that the retirements other than Lawrence are economic, no further analysis was done."[25] Hardwiring a single retirement date for the Westar units into 15 ARPs suggests that the Applicants are possibly selecting the outcome they want without providing credible and reliable support for the focus on such an objective or conclusion, and the outcome they want appears to be one in which the units are retired early and the merger savings appear to increase. Put another way, Applicants' haste to retire those generating units appears intended to remove those units as an option going forward. As I discussed previously, arbitrarily

[22] See KCP&L discovery response to KEPCo 9-08 (CONFIDENTIAL).
[23] Please note the 2017 Combined IRP Preferred Plan does not include the retirement of Lawrence 4&5.
[24] See Westar discovery response to KIC-10 and KIC-11.
[25] See KCP&L discovery response to KEPCo 9-05.

eliminating options before you start the IRP process is inconsistent with one of the basic purposes of an IRP process – to comprehensively evaluate all options and to determine what is needed moving forward. As previously discussed, Applicants simply have not provided an analysis that demonstrates how it went from high-level screening assumptions for 25 candidate resource options directly to the 16 selected ARPs.

Again, there was limited variability in the ARPs regarding renewables and a very static selection of capacity sizes and timing of installation. The base case included known 2017 wind additions of 580 MW and 2017 solar additions of 1.2 MW. Additionally, the base case included a 12 MW solar facility in 2027 in order to meet the Missouri RPS requirements[26]. Only two of the 16 ARPs considered a new wind project of 200 MW that would come online in 2020.

The rigidness and limited variability in the ARPs is also clearly illustrated by the observation that there is only 1.2% difference in the revenue requirement between lowest and highest revenue requirement. IRPs involving a reasonably broad range of potential options would produce much greater range of variability in the overall revenue requirement. In summary, the rigid assumptions and limited variability among the 16 APRs do not support the reasonableness or validity of the IRP.

Q. Why do you consider the 2017 Combined IRP non-exhaustive?

[26] See Ives direct testimony workpaper "2017 IC.pdf," at p. 13, section 1.3.

A. I consider the IRP to be non-exhaustive because the analysis fails to include an assessment of KCP&L/GMO and Westar each as standalone entities. Applicants acknowledged in discovery responses that they did not study those entities as standalone entities[27]. This is a critical flaw because it restricts the ability to directly compare the revenue requirement of the standalone entities to the merged entity, an analysis which is required to address the central issue of whether Kansas customers truly benefit from the merged entity.

Additionally, the 2017 Combined IRP fails to consider the original Westar unit retirement dates of the mid-to-late 2020s, which Westar had planned as a standalone entity[28]. An important analysis to benchmark Westar's potential benefit from the Merger would necessarily include comparison of their independent unit retirement plan directly to a Merger ARP scenario. The way the IRP was conducted makes this critical comparison impossible. This, in turn, restricts the ability of the Commission, KEPCo, or any interested party, to determine the extent of any possible benefit achieved from the earlier retirement dates. As a result, the ARP scenarios are simply comparing one retirement date, December 31, 2018, for each Westar resource in question, in different grouped combinations, to the alternative where the Westar resource(s) is not retired for the 20-year assessment period. The Applicants' single ARP scenario unnecessarily considers costs incurred for Westar resources far beyond Westar's independent

[27] See Westar discovery response to KIC-12 and KCP&L discovery response to KEPCo 9-13.
[28] See Westar discovery response to KIC-10 and KIC-11.

resource retirement date plans, and in so doing, considers costs that Westar never independently planned to incur. Nevertheless, the ARP scenario with no Westar retirements is only 0.33% greater in NVPRR terms than the Preferred Plan, which includes the early retirements.

With this analytical approach, it is simply not reasonable to conclude that the accelerated retirements are the best course of action when the analysis only looks at the situation where the retirement happens at the earlier date or does not happen at all, which, according to Westar, is not what will happen if the Merger does not occur.

Q. Why do you consider the 2017 Combined IRP to be a non-transparent process?

A. The Applicants claim that it is economic to accelerate the retirement of the Westar resources. However, as discussed, the analysis that purports to support this claim is seriously flawed because it is rigid and non-exhaustive. Additionally, the Applicants have not provided sufficient evidence or clarity in the 2017 Combined IRP or through discovery to demonstrate in a clear and coherent manner, the underlying economic analysis of the Westar units proposed to be retired. For example, when asked to provide reports associated with the planned retirement analysis, the Applicants provided a report that was not specific to the Westar units and also referred back to the 2017 Combined IRP.[29] Additionally, when asked to provide the specific study or model supporting the Applicants' statement, "Given

[29] See KCP&L discovery response to KEPCo 10-04a.

results show that the retirements other than Lawrence are economic, no further analysis was done[,]"[30] the Applicants referred to the 2017 Combined IRP. However, as I have demonstrated, the 2017 Combined IRP is flawed and unreliable, and the analysis presented does not demonstrate in a clear and coherent manner, the economic analysis underlying the accelerated retirement of the Westar units proposed to be retired.

Furthermore, the retirement of these units will create a greater reliance on the SPP energy market for balancing energy, particularly as Applicants' reliance on intermittent generating resources or DSM increases. Balancing energy is best described as the energy purchased to make up an energy deficiency or the energy sold to eliminate energy excess in the daily market. As an energy source, coal- and gas-fired generation are controllable and can be economically dispatched against prevailing market energy prices. The retirement of controllable resources and proposed replacement with intermittent generating resources like wind supply or DSM resources necessarily would result in less control of energy dispatch and, likely, a significant increase in exposure to balancing energy cost and risk. The Applicants do not identify the risks and possible cost exposure associated with the additional SPP interaction or, critically, address how they intend to manage these risks. The "plan" before the Commission is not complete in critical respects.

Given these omissions, I conclude that the process was non-transparent and the IRP is unreliable.

[30] See KCP&L discovery response to KEPCo 9-05.

IV. PREFERRED PLAN IDENTIFIED BY THE 2017 COMBINED IRP

Q. Please describe the Preferred Plan for the merged entity as identified by the 2017 Combined IRP.

A. Exhibit GC-2 details the Applicants' Preferred Plan. The 2017 Combined IRP identifies this plan as "IC6MD." It includes the retirement of the following Westar units: (a) Murray Gill 3&4, (b) Tecumseh 7 and (c) Gordon Evans Steam 1&2. This is a total reduction of 70 MW of coal-fired generation and 707 MW of gas-fired generation capacity. The plan incorporates the base case renewable generation assumptions mentioned earlier, together with the addition of a 207-MW CT resource in 2035 and a further 207-MW CT resource in 2036. Additionally, it includes the Base Case DSM assumptions and the Additional DSM assumption, *i.e.*, to increase DSM, in total, by approximately 700 MW over seven years.

Q. Do you consider the Preferred Plan to be in the public interest?

A. No. I consider the plan to be unnecessarily inflexible, as it reduces future resource options through its combination of early Westar retirements and reliance on new DSM programs.

Q. Please explain further.

A. Under the Preferred Plan, the combined entity moves from a capacity reserve margin of 24.3% in 2017 to 13.1% in 2020[31] and relies on further DSM programs to sustain a capacity reserve margin level above the 12% SPP requirement. The Preferred Plan assumes that the DSM contribution will increase by approximately 700 MW in seven years starting at 334 MW in 2017 and increasing to 1,037 MW in 2024, which would equate to approximately 9% of the merged company's total capacity. Approximately 73 percent, or 244 MW of the 2017 DSM starting level of 334 MW is in the Westar territory. Approximately 37 percent, or 258 MW, of the 700 MW total are projected to develop over the next seven years in the Westar service territory and 30 percent and 33 percent, respectively, in KCP&L-MO and GMO service territories. The Preferred Plan proposes to replace a known "steel in the ground" quantity of capacity, *i.e.*, the Westar units, with a forecasted DSM quantity, which naturally adds some uncertainty as to whether DSM programs will be implemented and penetration levels will be achieved as forecasted. As discussed below, there are numerous reasons to doubt the reliability of the forecasted penetration levels.

The retirement of the units removes the flexibility offered by the existing resources to manage DSM implementation and penetration outcomes that may differ in practice from the assumptions that were included in the 2017 Combined IRP. Consequently, if the DSM programs do not perform as expected or are found to be uneconomic and are discontinued, the Applicants have only one remaining

[31] See KCP&L discovery response to KEPCo 3-01, attachment "QKEPCo 3-01_ARP 2017 IC6MD.xlsx."

option, which is to secure additional resources in the form of new-build or existing generation resources, as the existing Westar units in question will be retired and unavailable to contribute to the capacity reserve margin. With respect to the option of developing new resources or procuring existing resources, KCP&L has stated that "It is a general long-term planning assumption that the company does not plan to meet significant capacity needs with purchased capacity[.]"[32] Arbitrarily eliminating the option to purchase capacity in a regional market awash in excess generating capacity to replace a DSM shortfall appears to suggest that the back-stop plan for a shortage in DSM penetration would be the development of new-build generation without considering the need to alter typical planning in order to procure potentially advantageous market-based alternatives that may result from such a large, near-term excess capacity reserve margin in SPP. Overall, the lack of flexibility in the Applicants' planning approach is detrimental to Kansas customers.

Q. What DSM assumptions does the Preferred Plan include?

A. The plan includes assumptions regarding the existing DSM programs and new DSM programs. Regarding the existing DSM programs, a forecasted estimate is provided for KCP&L's and GMO's respective Missouri Energy Efficiency Investment Act ("MEEIA") Cycle II program, which became effective on March 12, 2016. For Westar, an assumption was included based on its interruptible load contracts (198 MW in 2017) and the WattSaver program (47 MW in 2017).

[32] KCP&L discovery response to KEPCo 9-72.

The principle drivers of the DSM-related reductions from the IRP DSM component are new DSM programs that are proposed in the IRP but not yet filed with the Commission. The 2017 Combined IRP incorporated new DSM programs premised upon a study completed by the Applied Energy Group ("AEG") in April 2017, Kansas City Power & Light 2016 DSM Potential Study ("Potential Study").[33] The Potential Study was used to develop New DSM assumptions for KCP&L-Missouri and the KCP&L-GMO service territories. However, while the Potential Study did assess the KCP&L-KS service territory, no DSM assumption was included in the IRP for KCP&L-KS. Moreover, the Potential Study did not specifically study the Westar service territory. Instead, an Additional DSM scenario was created, which the Applicants claim, "is not assigned to any particular state or customer base."[34] As noted, to date, these new DSM programs have not been filed with this Commission or Missouri Public Service Commission.

The Potential Study evaluated "various categories of electricity DSM resources in the residential, commercial, and industrial sectors of KCP&L's service territory in Kansas and Missouri for the years 2019-2037."[35]

Q. **Why was the underlying data from the Potential Study for KCP&L-KS not utilized to create new DSM assumptions for that service territory?**

[33] For a copy of the report, see KCP&L discovery response to KEPCo 1-19.
[34] See KCP&L discovery response to KEPCo 10-41 (CONFIDENTIAL).
[35] See Kansas City Power & Light 2016 DSM Potential Study, Volume 1: Executive Summary Final Report, page iii (CONFIDENTIAL).

A. The Applicants did not include DSM assumptions for KCP&L-KS and stated in response to KEPCo 9-37: "Expansion of KS DSM programs was dropped due to a recent KCC Order regarding KCP&L's DSM programs."[36] I infer that this refers to the Commission Order issued on June 22, 2017, Docket No. 16-KCPE-446-TAR, regarding KCP&L's application seeking approval of its Demand-Side Management Portfolio Pursuant to the Kansas Energy Efficiency Investment Act ("KEEIA"), which was filed on April 6, 2016.[37] As discussed below, in that order, the Commission found that "KCP&L's proposed avoided capacity cost is too high to be practicable" [38] and made a number of modifications to KCP&L's DSM plan. Following that Order, on June 30, 2017, KCP&L filed a response withdrawing its application, explaining that:

> 2. The Company is, however, unable to move forward with the DSM Plan as modified by the Commission for the following reason:
>
> a. The DSM programs approved by the Commission in its Order were designed and proposed by the Company in a manner that is inconsistent with the Commission's modifications to the DSM Plan regarding avoided capacity cost, earnings opportunity, throughput disincentive and labor costs. As a result, the Company will be unable to implement the DSM plans approved by the Commission and the Company will need to determine whether it is possible to craft a portfolio of programs the Commission can approve based on the clarification contained in the Order.[39]

As discussed in detail below, the Commission in that case rejected the Company's proposal to base Avoided Capacity Costs on the cost of a new CT, the same

[36] KCP&L discovery response to KEPCo 9-37.
[37] Final Order, In re KCP&L Application for Approval of its DSM Portfolio, Docket No. 16-KCPE-446-TAR (issued June 22, 2017).
[38] *Id.* at ¶ 98.
[39] KCP&L Response to Commission Order at ¶ 2, In re KCP&L Application for Approval of its DSM Portfolio, Docket No. 16-KCPE-446-TAR (filed June 30, 2017).

Avoided Capacity Cost now being used by applicants to justify the 700 MW of DSM in seven years of proposed Base Case and Additional DSM.

Q. **Was any study conducted and new DSM program proposed for the Westar service territory?**

A. No.

Q. What is the basis for the Additional DSM assumption, which the Applicants claim, "is not assigned to any particular state or customer base."?[40]

A. The Additional DSM assumption was directly scaled from the underlying data from the Potential Study for the KCP&L-KS service territory[41], albeit not the finalized study results,[42] using a factor of 3.5 to reflect the size of the Westar service territory. Notably, in the Applicants own supporting workpaper, they describe that the scaling is, "Based on ratio of Westar demand to KCP&L-KS demand in 2019[.]"[43] When asked why the data for the KCP&L-KS service territory, which was used to support the Additional DSM assumption, differed from data contained in a separate file used to support the other new DSM programs, the Applicants responded that it was "because the Westar estimate was created before the DSM potential study was finalized and the estimates changed between the earlier version and the final version."[44]

[40] See KCP&L discovery response to KEPCo 10-41 (CONFIDENTIAL).
[41] See KCP&L discovery response to KEPCo 10-33 (CONFIDENTIAL).
[42] See KCP&L discovery response to KEPCo 10-34 (CONFIDENTIAL).
[43] See KCP&L discovery response to KEPCo 1-19, attachment "Westar DSM Scenario - KCPL BenCost Program Potential 11-16-2016 Confidential.xlsm." at tab "RAP- Westar", cell E2 (CONFIDENTIAL).
[44] See KCP&L discovery response to KEPCo 10-34 (CONFIDENTIAL).

Q. Are there other indications that it was intended to be a DSM assumption specifically for Westar?

A. Yes, the assumption's supporting workpaper filename says "Westar DSM scenario", and the assumption was included in the tab "DSM Westar" of the ARP supporting workpapers and was also included in the line item "DSM Westar"[45], which is used to determine the merged company's net peak load. However, while inquiring about the workpaper supporting the Preferred Plan (IC6MD) and the tab labeled "DSM Westar," KEPCo asked the important question "can the New DSM be achieved by Westar independently from the merger or does it rely on the merger taking place?" Applicants responded by saying "the 'NEW DSM' was included in Westar's DSM tab to avoid creating an additional DSM tab – but no decision has been made regarding allocation of the "new DSM". "[46]

Q. How do you reconcile this evidence with the Applicants' claim that it "is not assigned to any particular state or customer base."?

A. The only reasonable conclusion one can make is that it is designed to be a Westar-specific assumption. This is despite the Applicants' claims that "'NEW DSM" was included in Westar's DSM tab to avoid creating an additional DSM tab – but no decision has been made regarding allocation of the "new DSM""[47], and the "scenario was created to evaluate the impact of implementing more DSM than

[45] See KCP&L discovery response to KEPCo 3-01, attachment "QKEPCo 3-01_ARP 2017 IC6MD.xlsx."
[46] See KCP&L discovery response to KEPCo 9-46.
[47] *Id*.

planned[.]"[48] The Potential Study did not specifically assess the Westar service territory, but clearly a rudimentary attempt was made to scale Kansas-based DSM results to the size of the Westar territory. Describing it as something else does not make it so. The alternative position is that the Additional DSM largely has no basis, because if it is not being scaled to account for the size of Westar, the 3.5 scaling factor is arbitrary and without logical basis, and results in a DSM assumption that is entirely unrelated to the reality of the IRP.

Q. Does the Additional DSM assumption, which is included in the Preferred Plan IC6MD, play an important role in the determination that this Plan is the least-cost based on the Applicants' analysis?

A. Yes. The Applicants included an ARP, IC6M, that is identical to the Preferred Plan except that the Additional DSM assumption is removed. The IC6M is ranked 8th according to Table 17 in the 2017 Combined IRP. The plan requires two additional 207-MW CT units over and above the two already included in the Preferred Plan. This results in additional CT units in 2031, 2032, 2034 and 2036 in order to meet the SPP capacity reserve margin requirements. In other words, without the Additional DSM, Applicants will either fail to meet their SPP capacity reserve margin requirements, and incur additional costs and/or potential penalties, or build additional generating capacity, at an additional cost to ratepayers.

[48] See KCP&L discovery response to KEPCo 10-41 (CONFIDENTIAL).

V. CONCERNS REGARDING THE DSM ASSUMPTIONS USED IN THE 2017 COMBINED IRP

Q. Do you have specific concerns regarding the DSM assumptions that were used in the 2017 Combined IRP?

A. Yes. I have four main concerns; (1) inconsistency of forecasted DSM demand reductions; (2) the support for the new DSM programs does not pass a test of economic logic; (3) there are Kansas-specific regulatory risk factors that have not been considered in the Applicants' analysis; and (4) there has not even been a study conducted, or DSM program specifically designed for the Westar service territory, as it relates to any new DSM to be implemented there.

Q. Please address your concerns regarding inconsistency in the forecasted DSM demand reductions?

A. Applicants' projected DSM demand reductions are central to the Preferred Plan's ability to meet the SPP capacity reserve margin immediately following the retirement of Westar units and over the course of the 20-year assessment period. Therefore, it is imperative that there be a high degree of confidence in the DSM demand that has been incorporated into the IRP. The evidentiary record of this case, however, provides little if any basis for such confidence.

Q. **How so?**

A. Witness Ives relied upon the 2017 Combined IRP as support for the Applicants' decision to accelerate the retirement of the Westar resources as part of the resource planning for the merged entity. As discussed above, the analysis includes a specific set of DSM assumptions. However, it appears that the Applicants are simultaneously relying upon a different set of DSM assumptions in their estimate of the merged entity's capacity reserve margin over the 2017-2036 period with the accelerated retirement of the Westar resources. These alternative assumptions were provided in response to KEPCo 10-52d, which requested that Applicants, "provide the Joint Applicants' estimated reserve margin over the next ten years after the merger taking into account the retirement of these generating units." As a result, there is a clear conflict between the assumed DSM reductions in the IRP and the assumed DSM reductions employed in calculating the merged entity's capacity reserve margin following the accelerated retirement of the Westar resources. I see no legitimate reason for Applicants to use two different sets of assumptions to address essentially the same question.

Q. **Are there significant differences between the two sets of DSM assumptions?**

A. Yes. Exhibit GC-3 compares the two sets of DSM assumptions. As can be seen in that exhibit, there are significant differences in the forecasted DSM demand reductions in both the new DSM programs and the existing DSM programs. The DSM demand reductions outlined in the spreadsheet provided in response to

KEPCo 10-52d, which details the forecasted capacity reserve margin, are all lower than the DSM reductions included in the 2017 Combined IRP.[49]

For example, comparing the assumptions for 2020, we see values used for calculating the capacity reserve margin that are materially lower than those employed in the IRP -- reductions of 31 MW (24%) for KCP&L-MO, 61 MW (33%) for KCP&L-GMO and 50 MW (22%) for Westar (excluding the Additional DSM assumption). Furthermore, the above-mentioned capacity reserve margin spreadsheet does not include the Additional DSM assumption, which means that the Additional DSM was not even considered in calculating the capacity reserve margin despite this assumption forming a critical part of the Preferred Plan identified in the 2017 Combined IRP.

Q. Have you assessed whether the Preferred Plan would meet the SPP capacity reserve margin if the DSM assumption outlined in the spreadsheet provided to KEPCo 10-52d were incorporated?

A. Yes, see Exhibit GC-3, page 2 of 2. Applying the DSM assumptions employed by Applicants in response to KEPCo 10-52d, and keeping all the other components of the Preferred Plan constant, it can be seen that the merged entity would not meet the SPP capacity reserve margin requirement beginning in 2019 and would fail to meet the requirement over the majority of the 20-year horizon, *i.e.*, a total of 14 of the 20 years. This means that the merged entity would have to acquire

[49] KCP&L discovery response to KEPCo 10-52d, attachment "KEPCo_20171212-KEPCo_10_52-Att-QKEPCO 10-52_KCPL GMO Westar Long Term Capacity Forecasts.xlsx."

additional resources or routinely fail to meet the SPP capacity reserve margin requirement over the course of the next 20 years.

Q. Turning to your second concern, please describe the economic basis used to justify the new DSM programs.

A. The Potential Study identifies a set of new DSM programs, which passed a cost-effectiveness screening threshold. AEG "performed an economic screening of each measure, which serves as the basis for developing the economic and achievable potential, utilizing the measure information along with KCP&L's avoided cost data."[50]

The economic screening was predicated on the "Avoided Capacity Cost", which is an estimated value of the reduction in capacity needs if the DSM program were implemented. The analysis utilized an Avoided Capacity Cost estimate, which was provided by KCP&L and described as the "Company's most recent estimate of annual levelized capital cost for a new combustion turbine generator with the cost of a firm contract to supply natural gas to the plant."[51]

The Avoided Capacity Cost employed by Applicants was **[redacted]**, as outlined in the supporting spreadsheet provided in

[50] See Potential Study at Volume 3, page 3 (CONFIDENTIAL).
[51] See Potential Study at Volume 3, page 13 (CONFIDENTIAL).

response to KEPCo 1.19[52]. This is the same avoided cost included in both the June 2017 Annual Reports for KCP&L and GMO.[53]

Q. **Please explain how the new DSM programs do not pass a test of economic logic.**

A. The cost-effectiveness screening and subsequently identified DSM programs employ an Avoided Capacity Cost that is unrealistic and simply too high to be reasonable. The use of a new CT generator is not a reasonable measure for the Avoided Capacity Costs given the ample amount of excess capacity in the SPP region. A market-based view of Avoided Capacity Cost is a more appropriate lens to utilize.

Q. What is the current view of capacity and reserve margins in the SPP region?

A. The June 2017 SPP 2017 Resource Adequacy Report provides a 6-year assessment of the capacity position in SPP starting in 2017 and going through 2022.[54] The current Reserve Margin for 2017 is 29.7% and this is projected to decline to 25.9% by 2022. In MW terms, the excess capacity over and above the SPP Reserve Margin requirement is 8,913 MW in 2017 and 7,135 MW in 2022.

Q. Given this excess amount of capacity in the SPP region, is it reasonable to assume that capacity could be procured in the market at a lower price than a new CT generator?

[52] See KCP&L discovery response to KEPCo 1.19, attachment "KCPL BenCost Program Potential 03-08-2017 Confidential.xlsm" (CONFIDENTIAL).

[53] See KCP&L discovery response to KEPCo 9-01, attachments, "KEPCo 9-01_Kansas City Power Light Demand Side Resource Analysis.pdf" at Table 53, and "KEPCo 9-01_KCPL-Greater Missouri Operations Demand-Side Resource Analysis.pdf" at Table 48 (CONFIDENTIAL).

[54] Resource Adequacy Coordination, SPP 2017 Resource Adequacy Report, at p. 3 (June 19, 2017) *available at* www.spp.org/documents/52237/june%202017%20resource%20adequacy%20report.pdf.

A. Yes. Based upon my experience, I would fully expect that through a competitive Request for Proposal ("RFP") process, capacity could be procured at a lower price than the cost of a new CT. Indeed, the Applicants' own view of short-term capacity prices confirms this view. The Applicants state, in response to discovery request KEPCo 9-80, that the "2016 cost of annual capacity was assumed as $1.751/kw-month. Cost was escalated by 2.5% annually for 2017 – 2036."[55] The difference between that assumed capacity cost, together with the Applicants assumed transmission costs[56], and the **[redacted]** Avoided Capacity Cost that Applicants are using in the IRP equals **[redacted]**

Q. Has the Kansas Commission provided an opinion on the matter of Avoided Capacity Cost estimates in support of DSM programs?

A. Yes. There have been two recent Commission Orders in 2017 where the Commission made findings regarding Avoided Capacity Cost estimates: (1) Docket No. 16-KCPE-446-TAR, Order dated June 22, 2017 regarding KCP&L's application seeking approval of its Demand-Side Management Portfolio Pursuant to the KEEIA, which was filed on April 6, 2016; and (2) Docket No. 15-WSEE-532-MIS, Order dated September 14, 2017 regarding Westar's application made on May 7, 2015 for approval of interim budgets for its currently-effective energy efficiency programs during the pendency of the Evaluation, Measurement and

[55] KCP&L discovery response to KEPCo 9-80.
[56] See KCP&L discovery response to KEPCo 9-58, attachment "QKEPCo 9-58 CONF_GPE Supply-side Technologies_All.xlsx" (CONFIDENTIAL).

Verification process ("EM&V") for those programs pursuant to the Commission Order in Docket No. 15-WSEE-021-TAR. I note that my testimony in this regard is based solely on the non-confidential information pertaining to these cases.

Q. Could you please elaborate on the Commission Order findings regarding the KCP&L filing in relation to Avoided Capacity Cost?

A. The KCP&L filing estimated the Avoided Capacity Cost to be the cost of constructing a CT, which as discussed above, the Applicants also use as the basis for the Avoided Capacity Cost in the assessment of the DSM programs that are included in the 2017 Combined IRP.

The filing was made pursuant to KEEIA statute, which "directs demand-side program investments should be valued the same as traditional supply or delivery infrastructure, when practicable."[57] However, the Commission "finds that KEEIA's caveat "as much as practicable" requires the Commission to make a finding as to the present circumstances affecting the practicability of valuing demand-side programs the same as traditional supply or delivery infrastructure."[58] and "thus, concludes that when valuing traditional supply infrastructure the Commission may take into consideration the current availability of capacity."[59]

The Commission then came to the following conclusion regarding the use of the cost of a new CT as the basis for the Avoided Capacity Cost: "the evidence shows KCP&L will have access to abundant and inexpensive capacity for the

[57] See Final Order at ¶ 97, In re KCP&L Application for Approval of its DSM Portfolio, Docket No. 16-KCPE-446-TAR (issued June 22, 2017).
[58] See *id.*
[59] See *id.*

foreseeable future. Consequently, the Commission does not believe it would be practicable to build a new generation plant under such circumstances. Therefore, KCP&L's proposed avoided capacity cost is too high to be practicable."[60] Finally, the Commission found the Commission Staff's estimate of Avoided Capacity Cost to be "more in keeping with the requirements of KEEIA."[61] Staff's estimate of Avoided Capacity Cost was based upon the short-term cost of a capacity contract, plus transmission, because Staff reasoned that given the extensive excess capacity in the SPP, "the market value of capacity should remain below the cost of building capacity for the near future." [62]

Q. Please discuss Commission Order findings regarding the Westar filing in relation to Avoided Capacity Cost?

In the Order on the Westar filing, the Commission expressed concern about continuing Westar's Energy Efficiency Demand Response ("EEDR") program. In forming this view, the Commission relied upon the Commission Staff's analysis contained in its July 18, 2017 Report and Recommendation, which demonstrated that the program cost exceeds its benefits.[63] The Commission Staff report stated that, "It is not clear, however, what the value of demand response is when excess capacity exists in the market with stagnating peak load."[64] The report demonstrates the level of excess capacity in reference to the 2015 SPP Market

[60] See *id.* at ¶ 98.
[61] See *id.* at ¶ 99.
[62] See *id.* at ¶ 24.
[63] See Order Adopting Staff's Report and Recommendations at ¶ 13, In re Westar Energy Inc. for Approval of Interim Budgets for Energy Efficiency Programs, Docket No. 15-WSEE-532-MIS (issued Sept. 14, 2017).
[64] See Staff Report and Recommendation at p. 9, In re Westar Energy Inc. for Approval of Interim Budgets for Energy Efficiency Programs, Docket No. 15-WSEE-532-MIS (filed Jul. 18, 2017).

Monitoring Unit's 2015 State of the Market, published August 15, 2016, and observes that the 2015 capacity reserve margin was 4 times the required SPP capacity reserve margin.

Additionally, in reference to Westar's Avoided Capacity Cost of $57/kW-year[65], Commission Staff comments that, "valuing capacity at $57,000 per MW does not make sense with excess capacity in the market."[66] It is worth noting that the $57/kW-year Avoided Capacity Cost is approximately **[redacted]** that was used in the Applicants' 2017 Combined IRP. Commission Staff and, correspondingly, the Commission in its reliance on the Staff's demonstration and analysis are both concerned about this even lower Avoided Capacity Cost, let alone an estimate that is more than twice as high.

Q. Have there been any significant changes in the availability of capacity in the SPP markets since June 2017?

A. No, not to my knowledge.

Q. What are the implications of the Commission's above-stated concerns regarding Applicants' most recent DSM proposals when applied to their DSM proposals in the IRP?

A. Based on the Commission orders discussed earlier, the Commission should reject or materially modify Applicants' IRP DSM. Doing otherwise would require the

[65] See *id.*
[66] See *id.* at p. 13.

Commission to reverse its decisions made just months ago under circumstances virtually identical to today, so the use of the cost of a new CT should be rejected in favor of a much lower market-based Avoided Capacity Cost. Many of the new DSM programs likely will be found to be uneconomical and not viable once a market-based view of Avoided Capacity Cost is used in the economic screening process. At the very least, the new DSM programs should be significantly delayed until the true Avoided Capacity Cost increases, resulting in a reduction in DSM participation levels and associated capacity impacts currently assumed. The full extent of the impact on the new DSM programs' economic viability can only be determined through a new and rigorous economic screening process. It must be remembered that, if Applicants retire 777 MW of generating capacity by December 31, 2018, that capacity will not be available in the event that their proposed DSM additions are delayed or rejected.

Q. Regarding your third concern, please identify the Kansas-specific regulatory risk factors that have not been considered in the Applicants' analysis.

A. There is a risk that Westar's existing EEDR program may not continue in its current form beyond 2018. The EEDR program formed part of the Interruptible Load assumption in the 2017 Combined IRP, with the Interruptible Load estimated to deliver demand reductions of 198 MW for each year of the 20-year assessment period.

As mentioned above, the Commission and its Staff have concerns regarding Westar's Avoided Capacity Cost estimate used to justify the economic viability of the EEDR program. Additionally, "the Commission has concerns regarding the appropriateness of continuing a program that cost $10.7 million between June 2013 and June 2016 but was not used during the same time period."[67].

Despite these immediate concerns, the Commission concluded that "because the EEDR is a part of the Occidental Chemical Corporation special contract, the Commission finds it is in the public interest to extend the interim approval of the EEDR Program budget through the duration of Westar' s current special contract with Occidental Chemical. Furthermore, the Commission adopts Staff's recommendation that when the Occidental Chemical special contract is renegotiated in 2018, Westar should file EM&V along with its Application in the special contract docket and Staff will reevaluate the EEDR Program at that time."[68]

The Occidental Chemical contract, however, contributes a substantial part of the 198 MW Interruptible Load assumption used in the 2017 Combined IRP – * [redacted] **[69] Therefore, there is a risk that the EEDR program may not continue beyond 2018, which would eliminate **[redacted]** of the Interruptible Load estimate.

Q. Are there any risk factors regarding the Additional DSM assumption?

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[67] See Order Adopting Staff's Report and Recommendations at ¶ 13, In re Westar Energy Inc. for Approval of Interim Budgets for Energy Efficiency Programs, Docket No. 15-WSEE-532-MIS (issued Sept. 14, 2017)
[68] See *id.*
[69] See Westar discovery response to KEPCo 9-36, attachment "KEPCO-9.36.xlsx" (CONFIDENTIAL).

A. Yes. First, I have discussed at length that the only reasonable view one can take is that the Additional DSM assumption is attributable to Westar and not the other utilities that form the merged entity. Second, it is clear the high CT-based Avoided Capacity Cost assumption which has been used in the economic screening of the DSM programs that are included in the Additional DSM estimate, contradicts the Commission's recently stated view of an appropriate avoided cost value in light of the current excess capacity in the SPP region. Third, the Commission should be concerned about the reliability of the evidence, presented in this proceeding to justify the Additional DSM estimate given that, among other things, the estimate of the new DSM to be developed in the Westar service territory was not determined by a study of that service territory, but rather was determined through a rudimentary scaling of the draft results for KCP&L-KS service territory provided in the draft Potential Study.

Therefore, the Commission should reject Applicants' Additional DSM estimate, as it is not cost-justified, is unreliable, and those programs need to be significantly modified to reflect their real value.

Q. Have you assessed whether the Preferred Plan would meet the SPP capacity reserve margin if these Kansas-specific regulatory risk factors were to materialize?

A. Yes. See Exhibit GC-4. Taking the Preferred Plan as the basis and removing the **[redacted]** in connection with the Occidental Chemical EEDR estimate and removing the Additional DSM estimate while leaving the other components of the

Preferred Plan constant results in the merged entity failing to meet the SPP capacity reserve margin requirements as early as 2019. Additionally, the merged entity would continue to not meet the requirement in a majority of the 20-year assessment period, *i.e.*, a total of 13 years out of the 20 years. As I noted earlier, this would cause Applicants to incur additional costs to replace the short-fall in capacity and possibly penalties.

VI. CONCERNS WITH ACTIONS TAKEN THAT CONTRADICT THE 2017 COMBINED IRP PREFERRED PLAN

Q. Have the Applicants taken actions that contradict the Preferred Plan?

A. Yes. The discovery response to KEPCo 10-51(b), received on December 27, 2017, revealed that KCP&L has entered into two previously-undisclosed PPAs for wind resources totaling 444 MW.[70] These projects are expected to be completed by the end of 2018.

Q. Please confirm that these wind PPAs totaling 444 MW were not included as part of the 2017 Combined IRP analysis.

A. They were not included. The analysis included other wind projects totaling 581 MW, with Westar's 281-MW Western Plains wind development having reached commercial operation during 2017 and with Great Plains Energy's

[70] See KCP&L discovery response to KEPCo 10-51(b) (CONFIDENTIAL).

300-MW Rock Creek wind project, expected to become operational by the end of 2017[71].

Q. Does the Preferred Plan include further wind additions?

A. No. The Preferred Plan, which was the result of an analytical process described as being, "undertaken to determine the best economic path forward"[72] did not identify further wind additions.

In fact, the results of the analysis show that the addition of a 200 MW wind resource in 2020 (the only modeled wind scenario) to an ARP plan, and keeping the other inputs to the ARP constant, increases the NPVRR. For example, when a 200-MW wind resource is added to the Preferred Plan, as identified by plan number IC6DW, the revenue requirement increases by $117.9 million, resulting in it being ranked 5th least costly. Additionally, another ARP plan where a 200-MW wind resource is added, IC10W, moves the initial plan from a rank of 11th to 12th least costly due to a revenue requirement increase of $126.0 million.

Q. What do you conclude from these facts?

A. It is clear that the 2017 Combined IRP and the Preferred Plan derived from the analysis does not provide reliable evidence of how the Applicants plan on managing their power supply position as a merged entity. The addition of 444 MW of additional wind supply is a sizable installation of additional capacity and

[71] See Ives direct testimony workpaper "2017 IC.pdf" at p. 51.
[72] See *id.* at p. 13.

energy, and it is inconsistent with the Preferred Plan analysis. Additionally, Applicants' ARP analysis indicates that the addition of wind increases the plan implementation costs – Applicants are willingly moving away from what the IRP analysis suggests.

VII. CONCLUSIONS

Q. Please summarize your conclusions.

A. My overriding conclusion is that the Applicants' IRP is not a valid or reliable IRP and does not support the estimated merger savings asserted by Applicants. Applicants have predetermined critical assumptions, such as the date for the accelerated retirement of the Westar coal and gas-fired units, or even, more generally, the fact that there must be accelerated retirements, before even attempting to undertake a normal IRP practice of seeking to optimize resources and evaluate need based on a reliable delivery of supply at lowest cost and risk. Applicants' assumptions have created a need for additional expenditures on capacity that may not exist without those assumptions, *i.e.*, if Applicants employed a truly rigorous IRP process without prescribing the resulting solution. I have identified a number of serious concerns regarding the DSM assumption that formed part of the 2017 Combined IRP analysis, including; (1) an inconsistency of forecasted DSM demand reductions; (2) purported support for the new DSM programs that does not pass a test of economic logic; (3) the existence of Kansas-specific regulatory risk factors that have not been considered in the Applicants' analysis; (4) and no DSM study has been conducted to specifically design programs for the Westar service territory.

The IRP seems to have been crafted to produce the results that Applicants want, among other things a conclusion that the least-cost solution would be to add approximately 700 MW of DSM over a 7-year period from 2017 to 2024. But, even if one assumes that it is possible to develop that much DSM in such a short period, particularly when the analyses upon which Applicants base this estimate are seriously flawed and unreliable, the Avoided Capacity Cost Applicants have used to ostensibly show that their DSM programs are cost effective – the cost of a newly constructed CT – was rejected by the Commission just months when Applicants proposed it for their individual DSM programs. The Commission has correctly found that, with the SPP awash in excess generating capacity, the reasonable measure of avoided capacity is the cost of capacity (and associated transmission service) in the SPP market. Applicants' DSM proposal seems riddled with inappropriate assumptions.

Applicants appear intent on reducing the options available to them and to the Commission going forward. No compelling reason has been provided why Westar must retire more than 777 MW of generation by the end of 2018, yet they plan to do so. Once those units are retired, one obvious and cost-effective option to fill any gaps in the Applicants' power supply going forward, such as if their

DSM programs prove to be uneconomic or do not develop the 700 MWs of DSM they need, will be gone.

For these and the other reasons set forth in my testimony, I recommend that the Commission reject Applicants' IRP and mandate the steps I set forth in the following recommendations, including requiring the establishment of a rigorous and transparent IRP process.

VIII. RECOMMENDATIONS

If the Commission is inclined to approve the Merger, I recommend that any such approval be conditioned upon the following:

1. Applicants cannot retire any generating capacity without first filing an application with, and obtaining approval for the retirement from, the Commission, which cannot be filed before the conclusion of the first IRP process mandated by Recommendation No. 2, below.
2. Applicants shall be required to withdraw their IRP filed in this case and, within 60 days of the Commission's order approving the merger with conditions, file a detailed IRP consistent with the principles and components that I have identified above. The IRP filed pursuant to the Commission's order shall be evaluated through a public process in which stakeholders have the opportunity to offer their views in order for the Commission to determine whether the IRP plan meets Commission

requirements and to further determine that the Applicants are following the provided IRP.

3. As part of the process identified above, Applicants shall be required to make an IRP filing every three years with the Commission. This IRP process should continue for a period not less than ten years in order to ensure that the resource acquisition plans of the merged entity are developed and implemented in an open, transparent and cost-effective manner under the Commission's supervision.

4. The IRP process described above shall include market-tested pricing observed from competitive RFP processes, with the characteristics described by KEPCo witness Dismukes, undertaken by the Applicants. RFP processes also should be undertaken to develop a market-based Avoided Capacity Cost and market-based energy alternatives to be used in the economic screening of DSM programs and wind generation, especially in light of the large amount of excess capacity available in SPP.

Q. Does this conclude your testimony?

A. Yes it does. Thank you.

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Merger of Westar Energy, Inc. and Great Plains Energy Incorporated.	**)))))**	**Docket No. 18-KCPE-095-MER**

AFFIDAVIT OF GARRETT COLE

STATE OF GEORGIA)
) **ss**
COUNTY OF COBB)

Garrett Cole, being first duly sworn on his/her oath, states:

1. My name is Garrett D. Cole. I work in Marietta, Georgia and I am employed by GDS Associates, Inc. as a consulting engineer.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Kansas Electric Power Cooperative, Inc. consisting of forty-six (46) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Garrett Cole

Subscribed and sworn before me this 29TH day of January, 2018.

Notary Public

K. RUDITYS
MY COMMISSION EXPIRES
NOTARY
PUBLIC
FEBRUARY 10, 2019
COBB COUNTY, GEORGIA

My Commission Expires: 02/10/2019

GDS Associates, Inc
ENGINEERS & CONSULTANTS

GARRETT D. COLE, P.E.
Principal

EDUCATION / CERTIFICATION

Professional Engineer (P.E.) in the State of Georgia
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EXPERIENCE

GDS Associates, Inc. - Principal, Marietta, GA (2001 – Present)
Mr. Cole's more than 16 years of experience includes economic feasibility analyses of long-term and short-term power supply alternatives for industrials, municipals, electric cooperatives and joint action agencies, transmission access and pricing, market power analysis, strategic planning, power procurement and contract negotiations, financial forecasts, operating budget preparation and projections, asset feasibility studies, production cost dispatch modeling, legislation/regulatory risk modeling, risk management and hedging strategies, revenue requirement development and wholesale rate design.

RECENT PROJECT EXPERIENCE

Mr. Cole's notable recent experience with focus on key market and regulatory issues.

• Direct testimony for Cleveland Public Power in PUC Ohio Docket No. 14-1297-EL-SSO regarding First Energy's desire to incorporate the costs and benefits of unregulated coal and nuclear assets into a retail rate rider. Mr. Cole's direct testimony reviewed key issues of supply procurement resource upgrades as matters of importance in the recommendation.

• Support of Illinois-based, Southwestern Electric Cooperative in recently filed dockets and affidavit with the FERC (Docket Nos. EL15-70 and EL15-72) regarding recent capacity market clearing prices in MISO Local Resource Zone 4 (Illinois). Mr. Cole's support led to considered changes with respect to auction bidding protocol.

• Support of Missouri-based G&T, Associated Electric Cooperative in a detailed economic dispatch analysis and qualitative review of remaining a stand-alone Balancing Authority versus joining the SPP, MISO or PJM Regional Transmission Organizations (RTOs). Analysis included a complete review of energy markets, capacity markets, regional transmission projects cost allocation, transmission revenue requirements, stakeholder group participation, staffing, governance, jurisdictional implications and entry negotiation.

• Advisor to Georgia-based G&T, Oglethorpe Power Corporation in developing competitive benchmarks for the economic impacts of environmental legislation/regulation on Georgia Power's resources, including historical reviews of the Clean Air Act, RICE/NESHAP and the most recent focus on Clean Power Plan rulings (draft and final ruling).

• Key Advisor to Ohio-based joint action agency, American Municipal Power in development of Focus Forward Initiatives on distributed generation supply and policy and the federal and state renewable incentives resulting in such plans. The developed policy and rate design guide focuses on strategic and tactical plans for distributed generation, retail rates and interconnection best practices for wholesale power customers.

In addition to specific advice on various market and regulatory issues, Mr. Cole has served as a consultant to all of the following clients during key power supply resource planning decisions over the last 10 years:

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770-425-8100 • Fax 770-426-0303 • garrett.cole@gdsassociates.com
Marietta, GA • Austin, TX • Auburn, AL • Madison, WI • Manchester, NH • Orlando, FL • Hallowell, ME www.gdsassociates.com

Benton, Arkansas	Hagerstown, Maryland*	Perkasie, Pennsylvania
Conway, Arkansas	Thurmont, Maryland	Danville, Virginia*
Jonesboro, Arkansas	Williamsport, Maryland	Martinsville, Virginia
North Little Rock, Arkansas*	Chambersburg, Pennsylvania*	Radford, Virginia
Florida Municipal Power Agency*	Ephrata, Pennsylvania	Richlands, Virginia
Cleveland, Ohio*	Mont Alto, Pennsylvania	Salem, Virginia

* Largest electric municipality in its respective state

Oglethorpe Power Corp, GA	Associated G&T Electric Coop, MO	Northeast Texas Electric Coop, TX
Southwestern Electric Coop, IL	East Texas Electric Coop, TX	Central Virginia Electric Coop, VA

PAST PROJECT EXPERIENCE

Power Supply Procurement – Mr. Cole has extensive experience in performing economic analyses of power supply alternatives, including preparation, issuance, management of RFP process and respondents, evaluation of proposals, and recommendation to clients based on varying electric requirements, power supply portfolios, regional market factors and risk management strategies. Mr. Cole has experience with the preparation and issuance of power supply requests for proposals in Duke Energy Carolinas, Entergy, ERCOT, FMPP, MISO, New England ISO, PJM, Southern Company, Southwestern Power Administration and SPP, and has conducted economic feasibility analysis of the proposals and negotiated terms and conditions of contracts with the successful respondents. This type of work has been performed on behalf of various cooperative, municipal and state agency clients (complete list available on request).

Short/Long-Term Power Supply Strategic Planning – Mr. Cole has assisted clients with the development of short/long-term power supply strategic plans through a complete assessment of forecasted electric load and resource requirements. In addition, Mr. Cole has provided clients with customized diversification and risk management strategies based on city/cooperative goals for providing electric service, including comments on transmission access and planning, retail/wholesale rate design, expected ISO/RTO market developments, legislative/regulatory risk surrounding potential Greenhouse Gas/CO_2 emissions, among other topics.

Financial Planning, Operating Budget Projections and Billing Analysis – Mr. Cole has assisted clients with projections of revenues and operating expenses, long-term financial planning, regional power market projections and development of wholesale rates to member cooperatives. In addition, Mr. Cole monitors monthly billing for contract compliance and recommends short-term market purchases/sales to reduce cost and/or mitigate market and fuel pricing risks.

Long-Term Asset Feasibility Analyses – Mr. Cole has assisted clients with long-term asset feasibility analyses, including complete review of cost of construction/purchase, construction financing and accumulated Interest During Construction (IDC), debt service analysis and long-term financing arrangements, fixed and variable Operations & Maintenance (O&M), and fuel efficiency and fuel costs. In addition, Mr. Cole has also provided detailed sensitivity and break-even analyses where useful to communicate to clients the key risk factors and the magnitude of impact that various variables might have on economic feasibility of a long-term power project. These key risk factors often include fuel price sensitivities, legislation/regulatory uncertainty sensitivities (e.g. Environmental upgrades, carbon tax regulation) and congestion/transmission deliverability sensitivities, depending upon the physical or financial treatment of transmission deliverability regionally.

Great Plains Energy & Westar Integrated Company Resource Analysis Report, August 2017												
Preferred Plan - IC6MD												
Year	Balance	Balance w/Wind, Solar, PY CTs	Sell PPA	Buy PPA	CT's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)	Existing Capacity (MW)	Total Capacity (MW)	Reserve Margin
2017	1480	1481	200	0	0	580	1	334	50	13,097	12,897	24%
2018	1545	1545	200	0	0			383	1523	13,157	12,957	25%
2019	300	300	200	0	0			524	96	11,816	11,616	13%
2020	313	313	200	0	0			668		11,720	11,520	13%
2021	466	466	200	0	0			798		11,792	11,592	15%
2022	634	634	200	0	0			908		11,925	11,725	16%
2023	716	716	200	0	0			987		11,999	11,799	17%
2024	607	607	200	0	0			1037		11,939	11,739	16%
2025	715	716	100	0	0			1075		12,089	11,989	18%
2026	668	668	100	0	0			1111		12,089	11,989	18%
2027	609	609	100	0	0		12	1137		12,089	11,989	17%
2028	500	500	100	0	0			1157		12,072	11,972	16%
2029	409	409	100	0	0			1162		12,052	11,952	15%
2030	349	349	100	0	0			1174		12,052	11,952	14%
2031	280	280	100	0	0			1183		12,047	11,947	14%
2032	76	76	75	0	0			1187		11,910	11,835	12%
2033	-39	-39	0	50	0			1202		11,848	11,898	12%
2034	-95	-95	0	100	0			1217		11,848	11,948	12%
2035	-152	-152	50	0	207			1238		11,848	12,005	12%
2036	-338	-131	75	0	207			1260		11,727	12,066	12%

Sibley-1	50	Montrose-2	164
Sibley-2	47	Montrose-3	170
Sibley-3	364		
Lake Road 4/6	96		
Murray Gill 3	104		
Murray Gill 4	86		
Tecumseh 7	65		
Gordon Evans 1	153		
Gordon Evans 2	370		

Note: Retire Year is the actual calendar year of the retirement which is not the same as the retirement with respect to accreditation rules

Data Source: See KCP&L discovery response to KEPCo 3-01, workpaper for ARP 2017 IC6MD

Comparison of DSM Demand Reduction Forecasts (MW, 2017-2036)

KCP&L-Missouri service territory				
	2017 Combined IRP[1] Preferred Plan - IC6MD	Applicants' Response to KEPCo 10-52 Estimated Reserve Margin[2]		
Year	Total DSM (MW)	Total DSM (MW)[3]	Delta	% Difference
2017	30	30	0	0%
2018	49	34	(15)	-30%
2019	79	52	(27)	-34%
2020	125	95	(31)	-24%
2021	163	134	(28)	-17%
2022	197	162	(35)	-18%
2023	223	186	(37)	-17%
2024	239	209	(30)	-13%
2025	250	227	(24)	-10%
2026	261	242	(19)	-7%
2027	268	255	(14)	-5%
2028	272	260	(13)	-5%
2029	273	258	(15)	-5%
2030	276	257	(19)	-7%
2031	277	255	(23)	-8%
2032	278	254	(24)	-9%
2033	280	256	(24)	-9%
2034	285	261	(25)	-9%
2035	291	266	(25)	-9%
2036	298	272	(26)	-9%

1/ See KCP&L discovery response to KEPCo 3-01, workpaper for ARP 2017 IC6MD
2/ See KCP&L discovery response to KEPCo 10-52, attachment
KCPL GMO Westar Long Term Capacity Forecasts
3/ It is assumed that the 2017 Total value listed in the KEPCo 10-52 discovery response was in relation to MEEIA-MO

KCP&L-GMO service territory				
	2017 Combined IRP[1] Preferred Plan - IC6MD	Applicants' Response to KEPCo 10-52 Estimated Reserve Margin[2]		
Year	Total DSM (MW)	Total DSM (MW)[3]	Delta	% Difference
2017	60	60	(0)	-0%
2018	94	78	(16)	-17%
2019	122	73	(50)	-41%
2020	186	125	(61)	-33%
2021	224	155	(69)	-31%
2022	258	185	(73)	-28%
2023	280	212	(69)	-24%
2024	296	235	(60)	-20%
2025	309	257	(52)	-17%
2026	321	277	(45)	-14%
2027	328	296	(32)	-10%
2028	331	300	(31)	-9%
2029	329	300	(29)	-9%
2030	331	303	(28)	-9%
2031	331	303	(29)	-9%
2032	329	302	(27)	-8%
2033	333	305	(27)	-8%
2034	339	312	(27)	-8%
2035	347	320	(28)	-8%
2036	356	328	(28)	-8%

1/ See KCP&L discovery response to KEPCo 3-01, workpaper for ARP 2017 IC6MD
2/ See KCP&L discovery response to KEPCo 10-52, attachment
KCPL GMO Westar Long Term Capacity Forecasts
3/ It is assumed that the 2017 Total value listed in the KEPCo 10-52 discovery response was in relation to MEEIA-MO

Westar service territory[3]				
	2017 Combined IRP[1] Preferred Plan - IC6MD	Applicants' Response to KEPCo 10-52 Estimated Reserve Margin[2]		
Year	Total DSM (MW)	Total DSM (MW)	Delta	% Difference
2017	244	244	0	0%
2018	240	240	0	0%
2019	236	211	(25)	-11%
2020	231	181	(50)	-22%
2021	226	155	(71)	-31%
2022	221	150	(71)	-32%
2023	218	147	(71)	-33%
2024	215	144	(71)	-33%
2025	212	141	(71)	-33%
2026	210	139	(71)	-34%
2027	208	137	(71)	-34%
2028	206	135	(71)	-35%
2029	203	132	(71)	-35%
2030	201	130	(71)	-35%
2031	199	128	(71)	-36%
2032	198	127	(71)	-36%
2033	198	127	(71)	-36%
2034	198	127	(71)	-36%
2035	198	127	(71)	-36%
2036	198	127	(71)	-36%

1/ See KCP&L discovery response to KEPCo 3-01, workpaper for ARP 2017 IC6MD
2/ See KCP&L discovery response to KEPCo 10-52, attachment
KCPL GMO Westar Long Term Capacity Forecasts
3/ Please note the discovery response to KEPCo 10-52 did not include the Additional DSM forecast. For the purpose of the Delta comparison it has been omitted.

Conflicting DSM Demand Reduction Forecasts: Impact on IRP Preferred Plan's SPP Capacity Reserve Margin (2017-2036)

No change in data from Aug. 2017 IRP Preferred Plan IC6MD

No change

Highlighted Red when below 12% SPP Capacity Reserve Margin

DSM forecast used in Estimated Reserve Margin (KEPCO 10-52)

Year	Balance	Balance w/Wind, Solar, PY CTs	Sell PPA	Buy PPA	CT's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)	Existing Capacity (MW)	Total Capacity (MW)	Reserve Margin
2017	1480	1481	200	0	0	580	1	334	50	13,097	12,897	24%
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2022	634	634	200	0	0			497		11,925	11,725	12%
2023	716	716	200	0	0			545		11,999	11,799	12%
2024	607	607	200	0	0			588		11,939	11,739	11%
2025	715	716	100	0	0			625		12,089	11,989	13%
2026	668	668	100	0	0			658		12,089	11,989	13%
2027	609	609	100	0	0		12	688		12,089	11,989	12%
2028	500	500	100	0	0			694		12,072	11,972	11%
2029	409	409	100	0	0			691		12,052	11,952	10%
2030	349	349	100	0	0			690		12,052	11,952	9%
2031	280	280	100	0	0			685		12,047	11,947	9%
2032	76	76	75	0	0			682		11,910	11,835	7%
2033	-39	-39	0	50	0			688		11,848	11,898	7%
2034	-95	-95	0	100	0			699		11,848	11,948	7%
2035	-152	-152	50	0	207			712		11,848	12,005	7%
2036	-338	-131	75	0	207			727		11,727	12,066	7%

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