BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In re: Empire District Electric Company's Change to its	)
2016 Utility Resource Filing pursuant to	)
4 CSR 240 – Chapter 22.	)

NOTICE OF CHANGE IN PREFERRED PLAN

Liberty Utilities®
EMPIRE DISTRICT

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1. Introduction and Summary

The Empire District Electric Company ("Empire") filed its last triennial Integrated Resource Plan ("IRP") on April 1st, 2016, as required under Missouri Public Service Commission ("Commission'") Chapter 4 CSR 240-22. Empire's IRP described a Preferred Plan consisting of a combination of resource additions and retirements from 2016 to 2035. This plan was selected based on its ability to meet Empire's customers' long-term needs. Subsequent to its filing of its IRP, Empire determined that the Preferred Plan is no longer appropriate. Consistent with 4 CSR 240-22.080, Empire is notifying the Commission of its determination. Included herein is a description of all changes to the Preferred Plan and Acquisition Strategy, the impact of each change on the present value of the revenue requirement and all other performance measures specified in the last triennial compliance filing pursuant to 4 CSR 240-22.080(2), and the rationale for each change.

2. Empire's 2016 IRP Preferred Plan

Empire's 2016 IRP Preferred Plan described a set of resource additions and retirements between 2016 and 2035. These additions and retirements are illustrated in Table 1, which depicts the resource additions and retirements common to all plans analyzed, and those specific to the 2016 Preferred Plan.

Table 1: Resource Additions and Retirements Common to All Plans, and those Specific to the 2016 Preferred Plan[1]

Year	Common to All IRP Plans (Applies to Preferred Plan)	Plan 5 (Preferred Plan)
2016	By Mid-2016, Riverton 12 begins combined cycle operation (100 MW addition to the Empire system)	
2017		
2018		
2019		
2020		
2021		
2022		
2023	Energy Center Unit 1 assumed to retire for IRP purposes (82 MW loss)	
2024		
2025		
2026	Energy Center Unit 2 assumed to retire for IRP purposes (82 MW loss)	
2027		
2028	Meridian Way 105 MW Wind PPA expires (19 MW loss)	
2029		100 MW Combined Cycle, 100 MW Wind Resource
2030	Elk River 150 MW Wind PPA expires after 5-year extension (17 MW loss)	
2031		150 MW Wind Resource
2032		
2033	Riverton Units 10 and 11 assumed to retire for IRP purposes (33 MW loss)	
2034		
2035	Asbury Unit 1 assumed to retire for IRP purposes (194 MW loss)	200 MW Combined Cycle

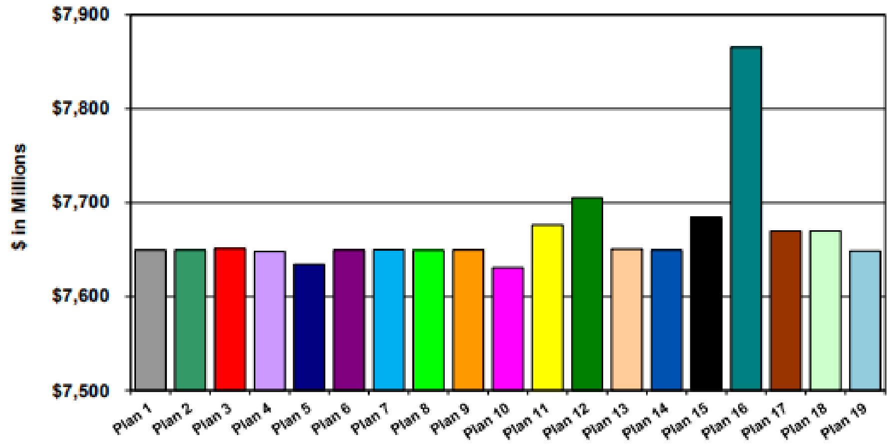
All nineteen plans analyzed in the 2016 IRP included: (1) Riverton 12 achieving commercial operation in 2016; (2) Energy Center 1 and 2 retiring in 2023 and 2026, respectively; (3) the Meridian Way wind Power Purchase Agreement ("PPA") expiring in 2028; (4) the Elk River wind PPA being extended to 2030; (5) Riverton 10 and 11 retiring in 2033; and, (6) Asbury retiring in 2035. In addition, Plan 5, the "Preferred Plan", included a 100 MW Combined Cycle ("CC") and 100 MW of wind in 2029, a 150 MW wind resource in 2031, and a 200 MW CC in 2035.

The minimization of the present worth of long-run utility costs was the primary criterion in selecting a Preferred Plan. Plan 5 was shown to be one of the least cost portfolios. Only

[1] Source: 2016 IRP Table 7-2

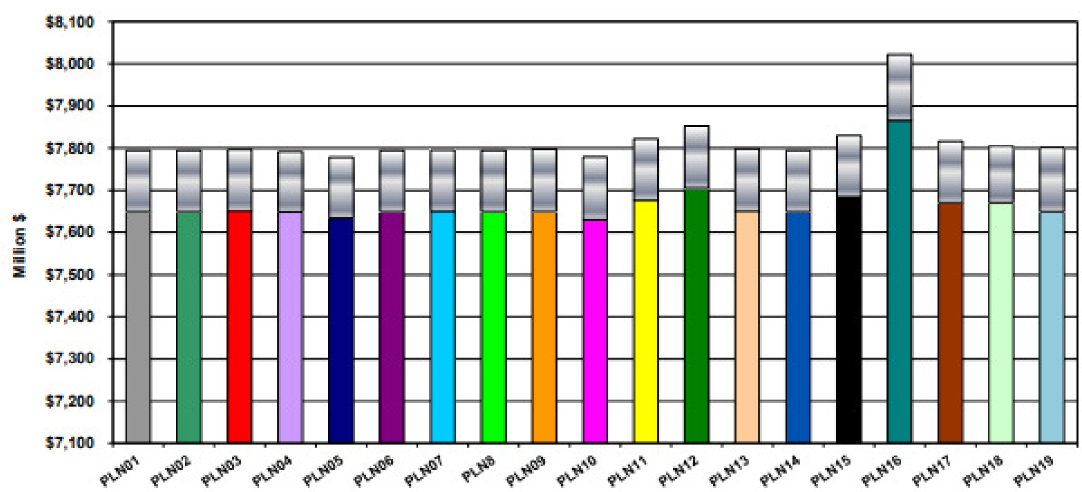
Plan 10, a low load scenario, was lower cost than Plan 5. Figure 1 compares the present worth of long-run utility costs under each of the 19 plans.

Figure 1: Present Worth of Long-Run Utility Costs under Different Plans[2]



Plan 5 also performed well on a risk-adjusted basis, with one of the lowest range of costs under uncertainty.

Figure 2: Risk-adjusted Present Worth of Long-Run Utility Costs under Different Plans[3]



[2] Source: 2016 IRP Figure 6-5

[3] Source: 2016 IRP Figure 6-120

3. Chapter 22 Requirements – Change in Preferred Plan

4 CSR 240-22.080(12) provides that in the event a utility determines that its Preferred Plan is no longer appropriate, the utility must notify the Commission of its determination and include therein a description of all changes to the Preferred Plan and Acquisition Strategy, the impact of each change on the present value of the revenue requirement and all other performance measures specified in the last filing pursuant to 4 CSR 240-22.080, and the rationale for each change.

4. Empire's Change in Preferred Plan

Empire filed what it termed the Customer Savings Plan ("CSP") application with the Commission on October 31, 2017 in Case No. EO-2018-0092. The CSP described that Empire customers could benefit significantly from the addition of up to 800 MW of wind to the portfolio in 2019 and 2020 and the retirement of the Asbury coal plant in 2019, among other changes to the 2016 Preferred Plan. The reduced cost of wind construction, combined with Empire's ability to efficiently monetize federal tax credits, were major drivers of the CSP.

Between November 2017 and March 2018, Empire led technical workshops, responded to stakeholder data requests, and submitted testimonies related to its CSP. Empire was a signatory to a non-unanimous stipulation filed on April 24, 2018 (as modified by an Addendum filed on May 7, 2018). The stipulation called for Empire to construct up to 600 MW of wind. The retirement of Asbury was deferred for future consideration. Hearings were held May 9, 2018 through May 11, 2018. The Commission issued a Report and Order on July 11, 2018, granting certain accounting requests and affiliate transaction waivers associated with Empire's CSP and finding, among other things, that "Empire has made reasonable decisions to acquire up to 600 MW of wind projects employing the financial measures set forth in the Joint Position, including use of a tax equity partner." Empire refers to a plan that includes constructing up to 600 MW of wind in 2020 as its New Acquisition Strategy.

Description of (and Rationale) for All Changes to the Preferred Plan and Acquisition Strategy

The principal difference between the New Acquisition Strategy and the 2016 Preferred Plan and Acquisition Strategy is the timing and size of wind and natural gas additions. While the 2016 Preferred Plan does not call for the addition of wind until 2029, the New Acquisition Strategy calls for up to 600 MW of wind to be added by 2020. The 2016 Preferred Plan would build a 100 MW CC in that same year (2029), add another 150 MW of wind in 2031, and add a 200 MW CC in 2035. On the other hand, the next addition under the New Acquisition Strategy is a 214 MW CT in 2035.

Table 2 illustrates how the planned resource additions change between the 2016 Preferred Plan and the New Acquisition Strategy.

Table 2: Comparison of Resource Buildout between the New Acquisition Strategy and the 2016 IRP Preferred Plan[4]

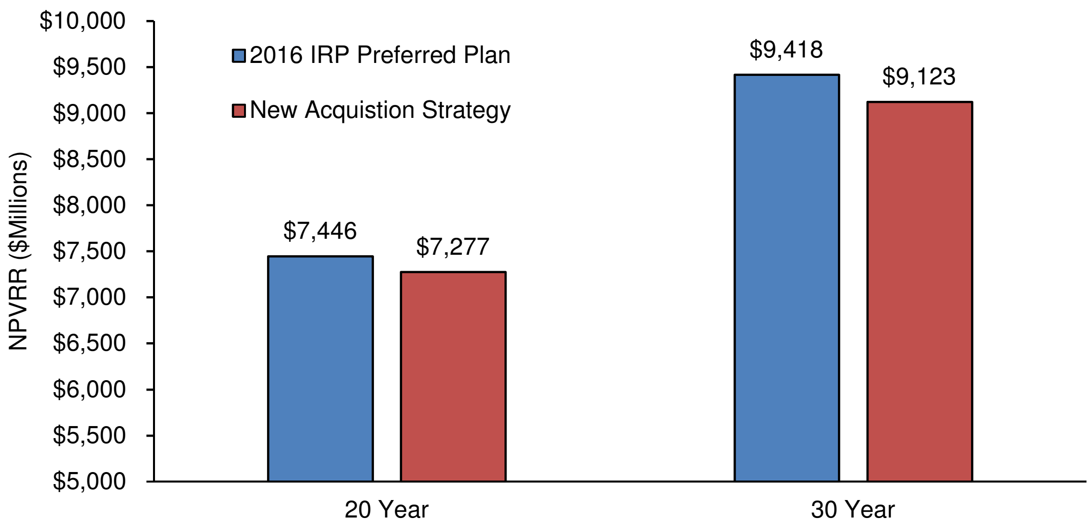
	New Acquisition Strategy	2016 IRP Preferred Plan
2016		
2017		
2018		
2019		
2020	600 MW Wind	
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		100 MW CC, 100 MW Wind
2030		
2031		150 MW Wind
2032		
2033		
2034		
2035	214 MW F Class CT	200 MW CC

[4] Source: EO-2018-0092 McMahon Affidavit, Figure 3 P.6. This table does *not* include any retirements contemplated in the two plans.

The Impact on the Present Value of the Revenue Requirement

The New Acquisition Strategy has a lower Present Value Revenue Requirement ("PVRR") than the 2016 Preferred Plan on both a 20 and 30-year basis. Figure 3 compares the PVRR for the 2016 Preferred Plan and the New Acquisition Strategy, under similar market conditions. Results under both plans use the ABB 2017 Fall Reference Case for gas, power and emissions prices. Relative to the 2016 IRP Preferred Plan, the New Acquisition Strategy results in $169 million in savings on a 20-year basis and $295 million in savings on a 30-year basis.

Figure 3: Present Value Revenue Requirement – 2016 Preferred Plan vs. New Acquisition Strategy[5]



Changes to the other performance measures as well as capacity balance sheets can be found in Appendix A.

5. Contingency Plans from 2016 IRP

Detailed Description (and Rationale) of Revised Resource Plan and Reason None of the Contingency Plans from 2016 IRP Were Chosen

4 CSR 240-22.080(12) states that if the utility decides to implement a New Acquisition Strategy that is not one of its contingency plans it shall explain why a contingency plan was not chosen. The utility shall also specify the range or combinations of outcomes for the

[5] Source: Updated Preferred Plan Exhibits; "Figure 3" (Tab)

critical uncertain factors that define the limits within which the new alternative resource plan remains appropriate.

The New Acquisition Strategy is not one of the 2016 IRP contingency plans. The New Acquisition Strategy was based on a number of assumptions that were not contemplated in the 2016 IRP. These include: (1) updated assumptions for wind capital costs, reflecting recent declines in costs and the ability for Empire to work with tax equity partners; (2) improved capacity factors for wind plants; and, (3) an updated modeling methodology that incorporated the Southwest Power Pool market and Empire's position within that market.

As part of the 2016 IRP, Empire developed 19 plans that it analyzed before settling on Plan 5 as the Preferred Plan. A description of the assumptions that went into each plan can be found in Table 3.

Table 3: Key Inputs for the 19 Resource Plans from the 2016 IRP[6]

[6] Source: 2016 IRP Table 6-9

Plan	Plan Description	Plan Type	DSM Portfolio	RPS	Carbon Costs for DSM Screening
1	Base Scenario	Base Plan	RAP Portfolio	None	Weighted
2	Base Scenario With RPS	Base Plan	RAP Portfolio	15 to 20% by 2021	Weighted
3	RAP + DSM	Base Plan	RAP + DSM	15 to 20% by 2021	Weighted
4	RAP – DSM	Base Plan	RAP – DSM	15 to 20% by 2021	Weighted
5	No DSM	Base Plan	None	15 to 20% by 2021	N/A
6	Federal Renewable Incentives	Other Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
7	High Environmental DSM	Other Contingency Plan	High Environmental	15 to 20% by 2021	High
8	Low Environmental DSM	Other Contingency Plan	Low Environmental	15 to 20% by 2021	Low
9	No Environmental DSM	Other Contingency Plan	No Environmental	15 to 20% by 2021	None
10	Low Load	Other Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
11	High Load	Other Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
12	High-High Load	Other Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
13	Low Fuel	Other Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
14	High Fuel	Other Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
15	Aggressive Electric Vehicle	Other Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
16	Early Asbury Retirement	Other Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
17	Highly Aggressive DSM	Required Plan	MAP Portfolio	15 to 20% by 2021	Weighted
18	Aggressive Capacity DSM	Required Plan	Aggressive Capacity Portfolio	15 to 20% by 2021	Weighted
19	Aggressive Renewable	Required Plan	None	Only renewables utilized	N/A

Notes:
DSM – Demand-side Management
RAP – Realistic Achievable Potential
MAP – Maximum Achievable Potential
RPS – Renewable Portfolio Standard

Plans 6 through 16, shown in Table 5, are considered Contingency plans. Most of these plans result in alternate resource plans addressing differing futures for loads, fuel prices, and environmental costs. Plans 15 and 16 examine the early retirement of a coal unit and a future with a high penetration of electric vehicles, respectively. Plans 11, 12 and 16 require a new resource at an earlier point in the future than does the 2016 Preferred Plan.

Table 4: 2016 IRP Contingency[7]

YEAR	Plan 5-No DSM (2016 Preferred Plan)	Plan 6-Fed Renew Incent	Plan 7-High CO2	Plan 8-Low CO2	Plan 9-No CO2	Plan 10-Low Load
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029	100 MW CC 100 MW Wind	100 MW Wind	100 MW Wind	100 MW Wind	100 MW Wind	100 MW Wind
2030						
2031	150 MW Wind	100 MW CC 150 MW Wind	100 MW CC 150 MW Wind	100 MW CC 150 MW Wind	100 MW CC 150 MW Wind	150 MW Wind
2032						
2033						100 MW CC
2034						
2035	200 MW CC	200 MW CC	200 MW CC	200 MW CC	214 MW CT Frame F	100 MW CC

7 Source: 2016 IRP Table 6-10

YEAR	Plan 11-High Load	Plan 12-High-High Load	Plan 13-Low Fuel	Plan 14-High Fuel	Plan 15-Electric Vehicles	Plan 16-Asbury Retirement
2018						
2019						
2020						
2021						
2022						
2023						100 MW CC
2024						
2025						
2026		100 MW CC				100 MW CC
2027	100 MW CC					
2028						
2029	100 MW Wind	100 MW Wind	100 MW Wind	100 MW Wind	100 MW CC 100 MW Wind	100 MW Wind
2030						
2031	150 MW Wind	150 MW Wind	100 MW CC 150 MW Wind	100 MW CC 150 MW Wind	150 MW Wind	100 MW CC 150 MW Wind
2032						
2033		100 MW CC			100 MW CC	
2034						
2035	200 MW CC	200 MW CC	214 MW CT Frame F	200 MW CC	200 MW CC	

As seen in the plans above, neither the alternative resource plans nor the 2016 Preferred Plan found early investments in wind to be a least-cost outcome. Updated assumptions to wind costs and performance, as well as the modeling of tax equity financing, resulted in in the New Acquisition Strategy having the lowest PVRR.

Empire has not included any contingency plans in its development of the New Acquisition Strategy. No contingency plans were chosen from the 2016 IRP as all of the other resource plans analyzed were developed without the benefit of updated pricing and assumptions around the potential cost and performance for new wind. Empire anticipates that this New Acquisition Strategy is appropriate under a number of scenarios, including high and low fuel prices, which is outlined in more detail in Section 7. Additionally, Empire believes that under other uncertain factors, such as increasingly aggressive federal or local environmental policies, including imposition of a carbon tax, the New Acquisition Strategy would continue to be appropriate. Finally, Empire plans to file its Triennial IRP in April 2019, which will include further contingency plans and analysis, developed under a range of uncertain factors.

6. Implementation Plan

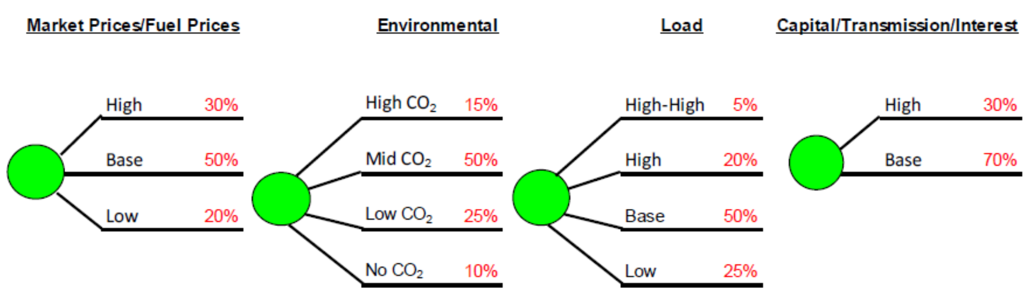
In order to implement Empire's New Acquisition Strategy, Empire will seek certificates of convenience and necessity associated with the planned construction. Empire filed a Notice of Intended Case Filings on July 13, 2018 (File No. EA-2019-0010) in preparation for the filing of such an application. The subject CCNs represent the next step in the New Acquisition Strategy as Empire moves toward specific wind projects and the related customer benefits.

7. Critical Uncertain Factors

Specifications of Ranges/Combinations of Outcomes for Critical Uncertain Factors Where the New Alternative Resource Plan Remains Appropriate

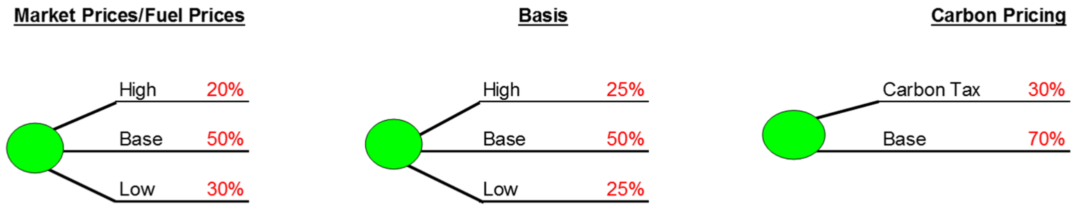
Empire's 2016 Triennial IRP examined a number of critical uncertain factors, including market prices, fuel prices, carbon prices, load, and capital/interest costs. The critical uncertain factors tested in the 2016 IRP can be found in the figure below.

Figure 4: 2016 IRP Critical Uncertain Factors



Empire re-examined these critical uncertain factors in the context of modeling the CSP. Empire determined that electricity market and fuel prices remained a critical uncertain factor, and included those in the CSP modeling. Empire reassessed the probability of carbon pricing scenarios since the 2016 IRP, and estimated that while a CO2 tax was still a possibility in the future, it was likely to be delayed. Empire continued to model carbon pricing as a critical uncertain factor, but with a different range of probabilities, with $0 carbon as the base case and ABB's carbon price forecast (beginning in 2030) as the high case. Load was not modeled as a critical uncertain factor as part of the original CSP analysis, but per request from Staff, was later modeled as part of a data request. Finally, capital and interest costs were not modeled as a critical uncertain factor in the Customer Savings Plan. Instead, Empire modeled potential price congestion risk associated with proposed wind facilities as the third critical uncertain factor.

Figure 5: Customer Savings Plan Critical Uncertain Factors

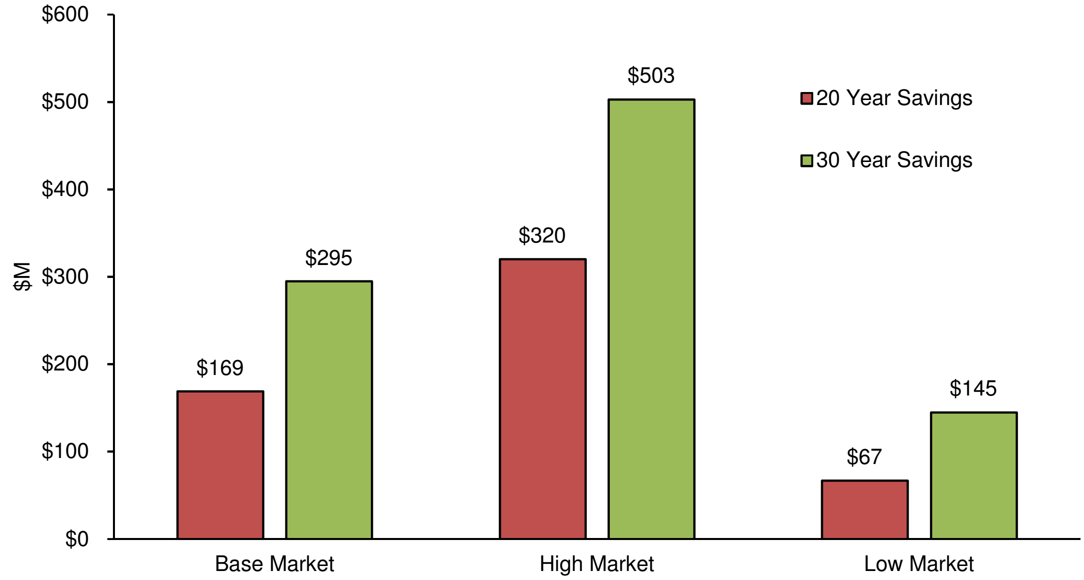


In determining the New Acquisition Strategy, Empire conducted additional modeling, including updating the CSP analysis to include 600 MW of wind and retaining Asbury, updating wind acquisition costs, and updating market and fuel prices.

Empire tested the New Acquisition Strategy under a range of fuel and electricity prices. Empire did not model the New Acquisition Strategy under the other critical uncertain factors modeled in the CSP: basis congestion and carbon pricing. In light of the 2016 election and new Trump administration policy, it was determined that the likelihood of near-term carbon pricing was diminished, and a carbon price would not be part of Empire's base case fuel and market price forecasts. Empire believes, however, that the New Acquisition Strategy would continue to be appropriate in the event of imposition of a future carbon tax. The presence of carbon-free wind energy in the plan, as well as likely higher prices in the event of a carbon tax, would benefit the New Acquisition Strategy relative to the 2016 Preferred Plan. Additionally, between the CSP filing and the development of the New Acquisition Strategy, Empire received actual wind project bids as the result of a request for proposal. This provided clarity that the wind projects Empire could acquire would be in or near Empire's service territory, decreasing the likelihood for congestion basis risk.

The New Acquisition Strategy generated significant savings under base fuel and electricity prices, high fuel and electricity prices, and low fuel and electricity prices when compared to the 2016 Preferred Plan as shown in Figure 6. The base scenario includes Empire's base case forecast assumptions, which reflect the latest forward price curves for fuel and electricity prices from ABB (2017 Fall Reference Case). The High Market and Low Market cases use the ABB results that include high fuel and electricity prices and low fuel and electricity prices, respectively.

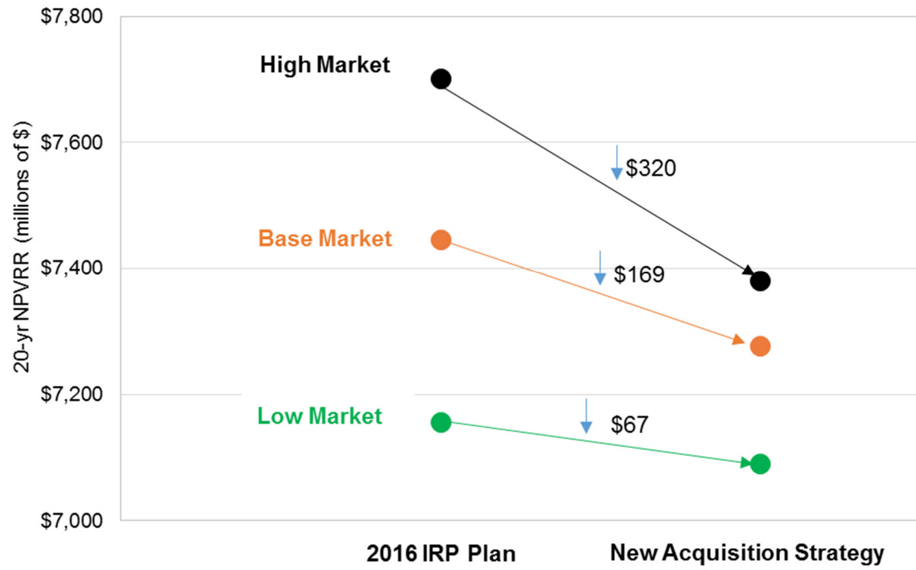
Figure 6: New Acquisition Strategy Savings under Base, High, and Low Market Conditions[8]



As shown in Figure 4, the 20-year present value revenue requirement from the New Acquisition Strategy is lower in all cases relative to the 2016 Preferred Plan. Moreover, the High Market and Low Market cases in the New Acquisition Strategy form a tighter band around the base case than the 2016 Preferred Plan, implying a portfolio that is at lower risk to market forces.

[8] Source: Updated Preferred Plan Exhibits; “Figure 6” (Tab)

Figure 7: Present Value Revenue Requirement for the 2016 IRP Plan vs. New Acquisition Strategy – High, Base and Low Market[9]



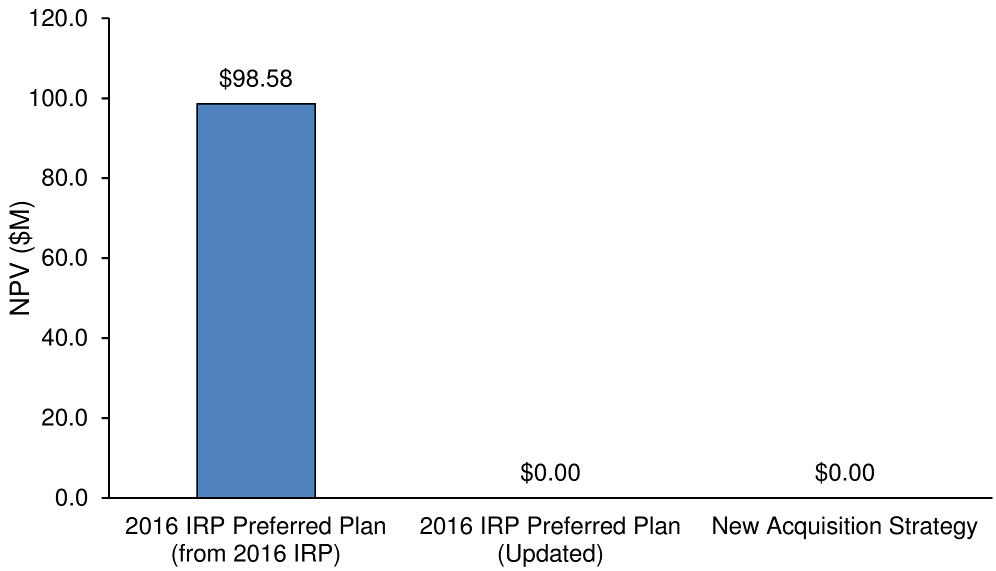
9 Source: EO-2018-0092 McMahon Affidavit, Figure 2 P. 5

Appendix: Impact of Changes on Other Performance Measures and Capacity Balance

Impact of Changes on Other Performance Measures

4 CSR 240-22.060 states that the utility shall "specify, describe, and document a set of quantitative measures for assessing the performance of alternative resource plans." Section 060 describes the performance measures as including at least the following: (1) present worth of utility revenue requirements; (2) present worth of probable environmental costs; (3) present worth of out-of-pocket costs of participants in demand-side programs and demand-side rates; (4) levelized annual average rates; (5) maximum single year increase in annual average rates; and (6) financial ratios. In this section, Empire compares the performance measures of the New Acquisition Strategy to the 2016 Preferred Plan. The 2016 Preferred Plan performance measures are shown below under both the updated market assumptions that were run in the CSP and for the New Acquisition Strategy and the market assumptions that were run in the 2016 IRP.

Figure 8: Present Worth of Probable Environmental Costs[10]



Probable environmental cost in the 2016 IRP were developed based upon the expected risk levels of implementation of carbon regulations and CO2 prices. In the updated CSP analysis, carbon pricing has been removed from the base case, high gas, and low gas price assumptions; thus, the probable environmental costs are zero. As discussed above, in light of

[10] Source: Updated Preferred Plan Exhibits; "Figure 8" (Tab)

the Trump administration's policy regarding environmental or carbon pricing, carbon was removed from the base case as part of the CSP and analysis of the New Acquisition Strategy.

Figure 9: Present Worth of DSM Participant's Costs[11]

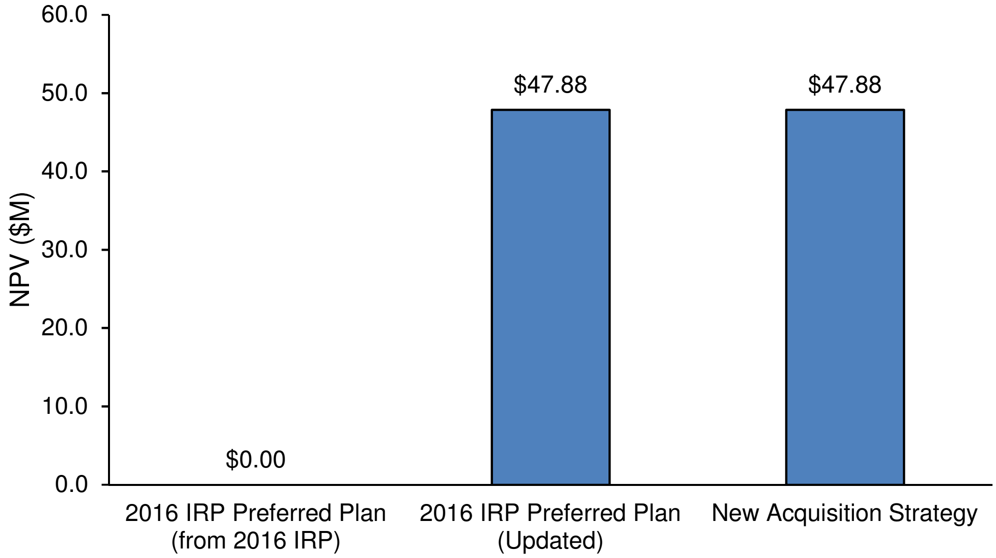
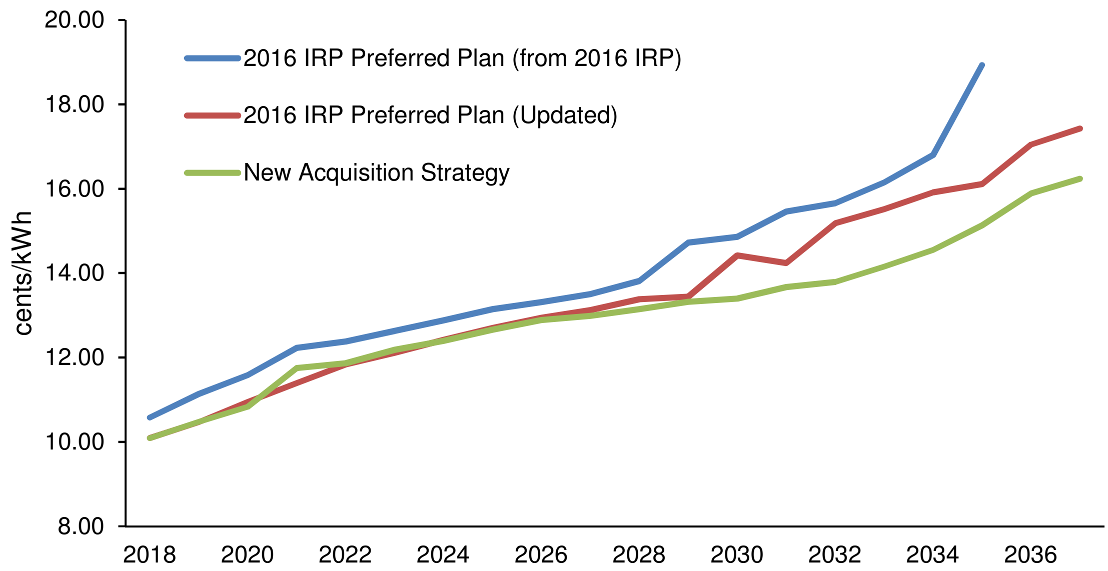


Figure 10: Average System Rate Revenue[12]



[11] Source: Updated Preferred Plan Exhibits; "Figure 9" (Tab)

[12] Source: Updated Preferred Plan Exhibits; "Figure 10" (Tab)

Figure 11: Average Rate Change – Percent of Revenue[13]

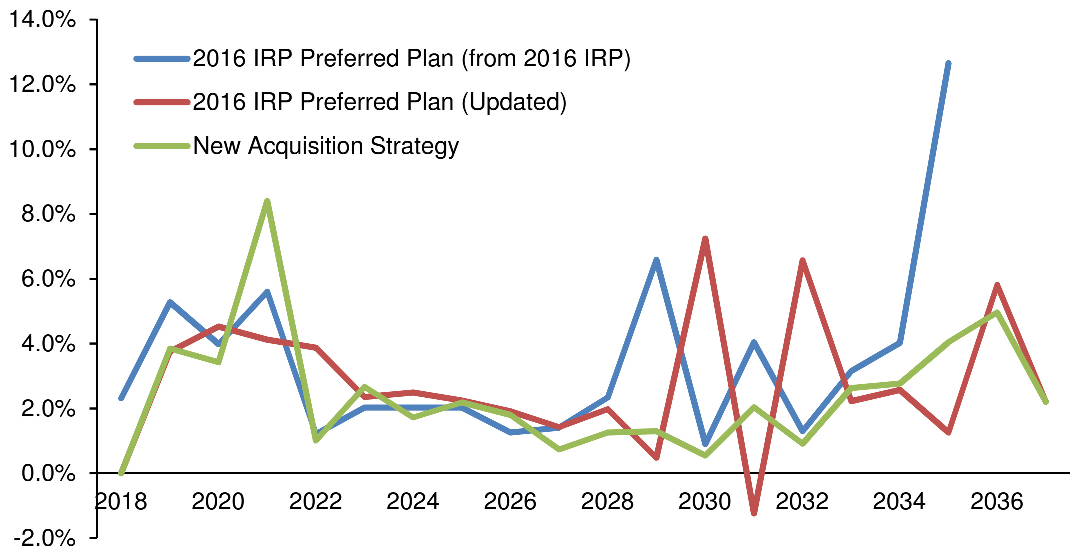
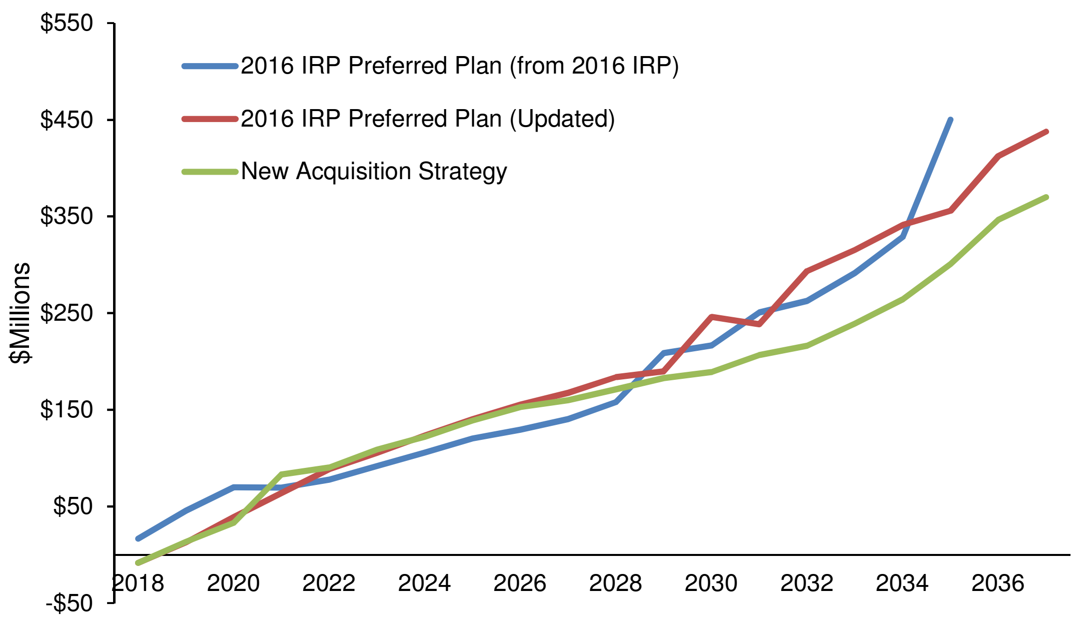


Figure 12: Cumulative Rate Increases[14]



[13] Source: Updated Preferred Plan Exhibits; "Figure 11" (Tab)

[14] Source: Updated Preferred Plan Exhibits; "Figure 12" (Tab)

Figure 13: Capital Forecast[15]

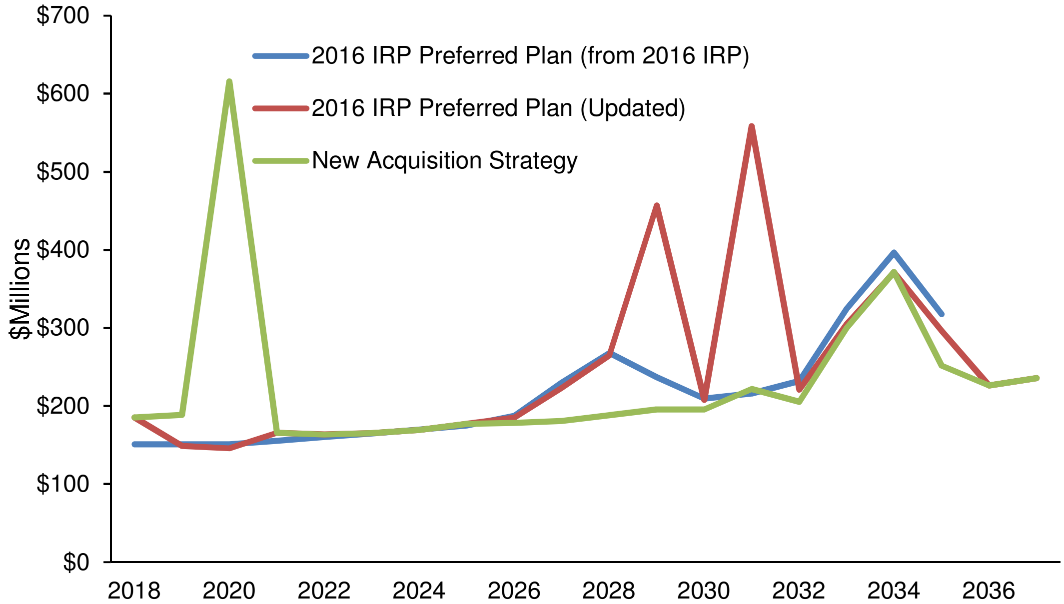
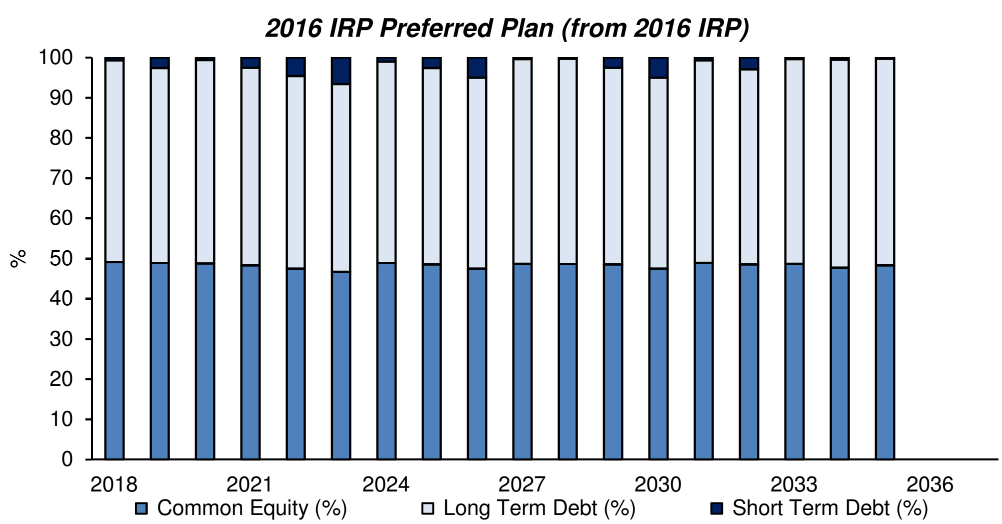


Figure 14: Capitalization Ratios[16]



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15 Source: Updated Preferred Plan Exhibits; "Figure 13" (Tab)

16 Source: Updated Preferred Plan Exhibits; "Figure 14" (Tab)

Figure 15: 2016 IRP Preferred Plan Finances[17]

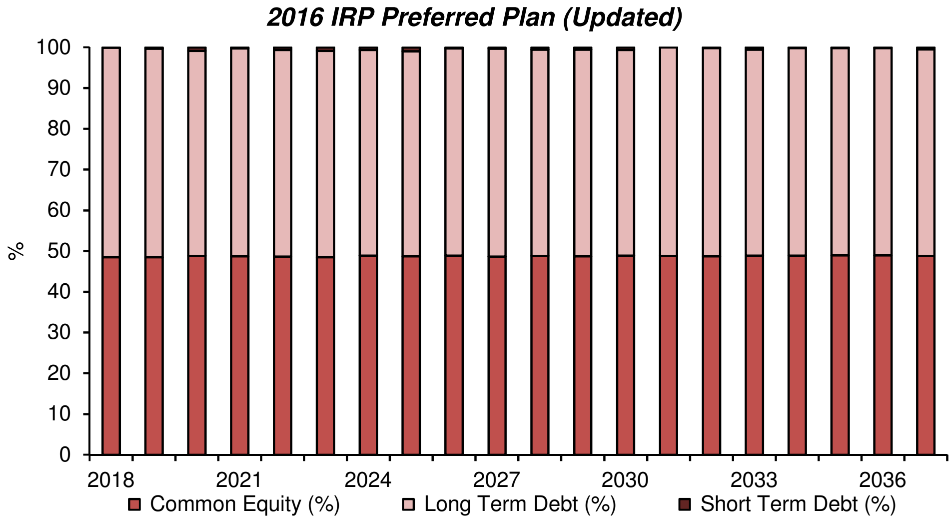


Figure 16: New Acquisition Strategy Finances[18]

[17] Source: Updated Preferred Plan Exhibits; "Figure 15" (Tab)

[18] Source: Updated Preferred Plan Exhibits; "Figure 16" (Tab)

Figure 17: Debt to Capital Ratio[19]

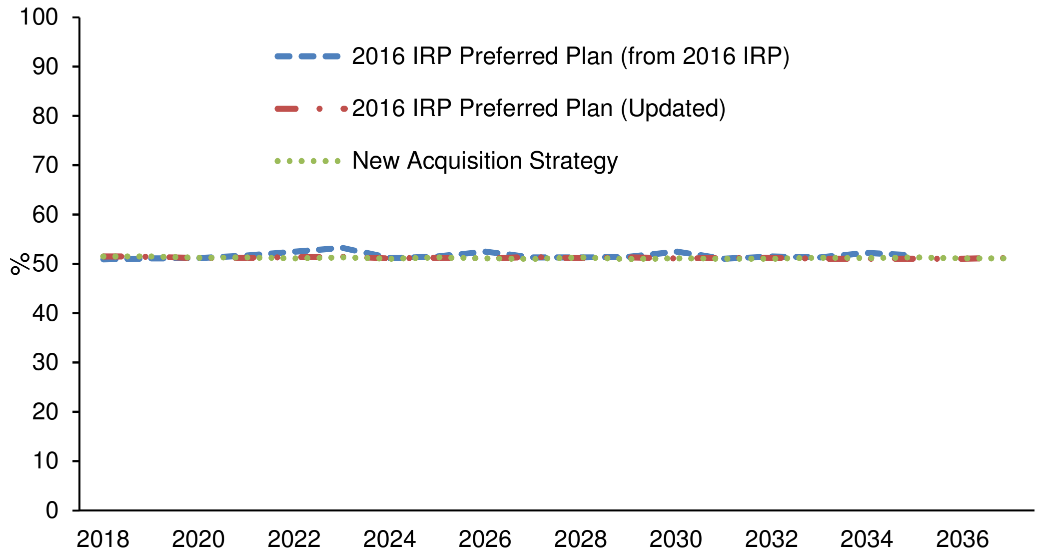
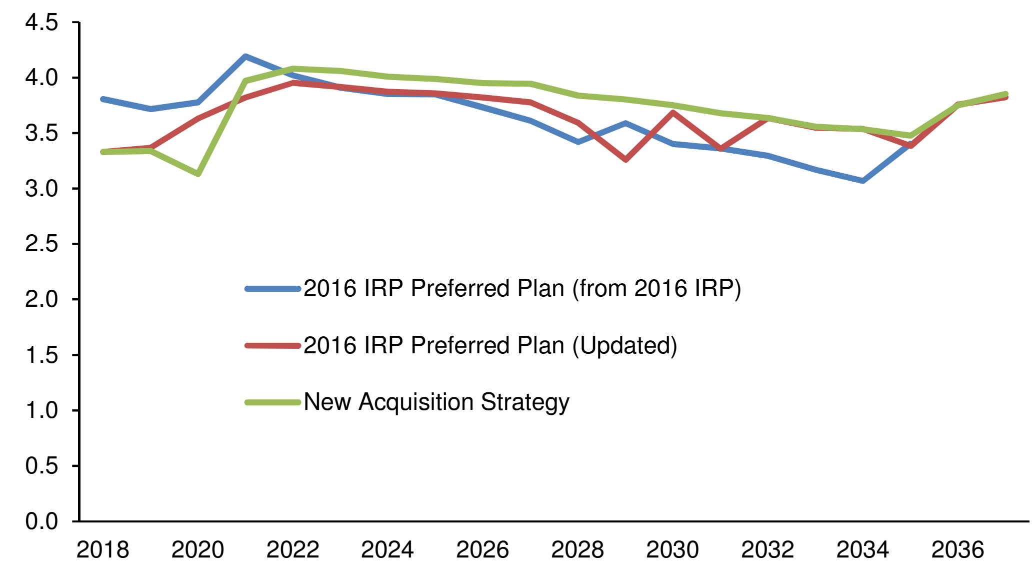


Figure 18: Pretax Interest Coverage Ratio[20]



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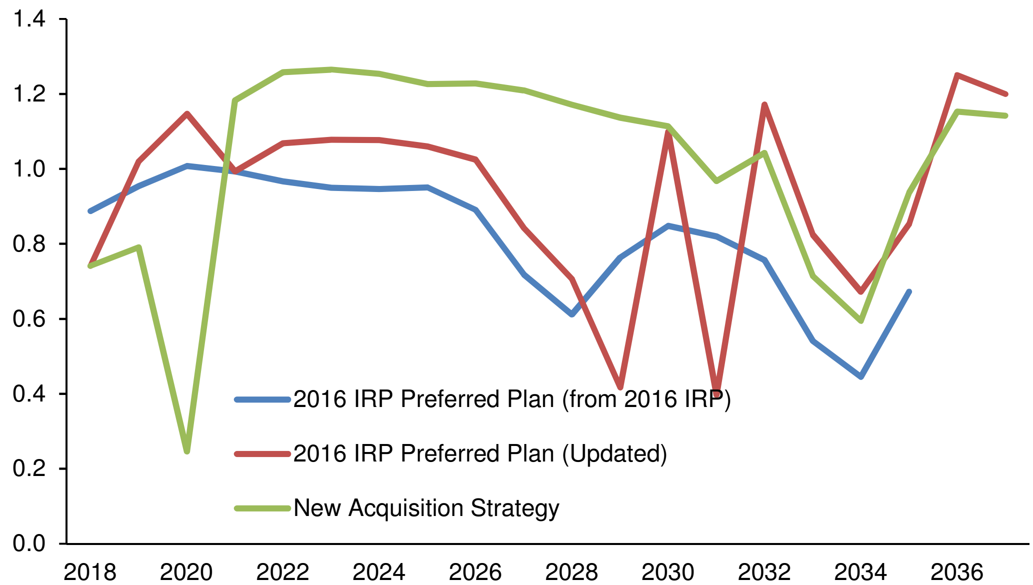
[19] Source: Updated Preferred Plan Exhibits; "Figure 17" (Tab)

[20] Source: Updated Preferred Plan Exhibits; "Figure 18" (Tab)

Figure 19: Net Cash Flow to Capital Expenditures[21]



Capacity Balance

The capacity position of Plan 5 from the 2016 IRP (Preferred Plan and the New Acquisition Strategy can be found in Figure 20.

Figure 20: Capacity Position – 2016 Preferred Plan vs. New Acquisition Strategy

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Plan 5 - 2016 IRP Preferred Plan																				
Total System Capacity	1,472	1,472	1,472	1,472	1,472	1,390	1,390	1,390	1,308	1,308	1,308	1,404	1,404	1,409	1,409	1,376	1,376	1,382	1,382	1,382
Base Summer Peak Demand	1,123	1,121	1,119	1,120	1,120	1,120	1,121	1,123	1,124	1,127	1,130	1,133	1,136	1,140	1,145	1,151	1,157	1,164	1,168	1,172
Capacity Reserves	349	351	353	352	352	270	269	267	184	181	178	271	268	269	264	226	219	219	215	211
Capacity Needs																				
% Reserve Margin	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%
% Capacity Margin	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
Required Capacity	135	135	134	134	134	134	135	135	135	135	136	136	136	137	137	138	139	140	140	141
Capacity Balance	**215**	**216**	**218**	**218**	**218**	**136**	**134**	**133**	**49**	**46**	**42**	**135**	**132**	**133**	**127**	**88**	**80**	**79**	**75**	**70**
Reserve Margin	31%	31%	32%	31%	31%	24%	24%	24%	16%	16%	16%	24%	24%	24%	23%	20%	19%	19%	18%	18%

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
New Acquisition Strategy																				
Total System Capacity	1,472	1,472	1,472	1,562	1,563	1,481	1,481	1,481	1,381	1,382	1,382	1,363	1,362	1,363	1,363	1,330	1,329	1,350	1,350	1,350
Base Summer Peak Demand	1,123	1,121	1,119	1,120	1,120	1,120	1,121	1,123	1,124	1,127	1,130	1,133	1,136	1,140	1,145	1,151	1,157	1,164	1,168	1,172
Capacity Reserves	349	351	353	443	443	361	359	358	257	254	251	229	227	222	217	179	172	186	182	178
Capacity Needs																				
% Reserve Margin	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%
% Capacity Margin	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
Required Capacity	135	135	134	134	134	134	135	135	135	135	136	136	136	137	137	138	139	140	140	141
Capacity Balance	**215**	**216**	**218**	**309**	**309**	**226**	**225**	**223**	**122**	**119**	**116**	**93**	**91**	**86**	**80**	**41**	**33**	**46**	**42**	**37**
Reserve Margin	31%	31%	32%	40%	40%	32%	32%	32%	23%	23%	22%	20%	20%	20%	19%	16%	15%	16%	16%	15%

[21] Source: Updated Preferred Plan Exhibits; "Figure 19" (Tab)