DIRECT TESTIMONY

Michael J. Majoros, Jr.

STATE OF NORTH DAKOTA

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the matter of:

NORTHERN STATES POWER COMPANY ADVANCE PRUDENCE – ACQUISITION OF THE 375MW MANKATO ENERGY CENTER AND THE 345MW MANKATO ENERGY CENTER II

CASE NO. PU-18-403

Testimony of Michael J. Majoros, Jr.

May 28, 2019

50 PU-18-403 Filed 07/16/2019 Pages: 42
Exhibit 6 - Direct Testimony of Michael J. Majoros, Jr. with attachments - redacted
Northern States Power Company

TESTIMONY OF MICHAEL J. MAJOROS, JR.

I. INTRODUCTION

Q. Please state your name and summarize your position and qualifications.

A. My name is Michael J. Majoros, Jr. I am president of Snavely King Majoros & Associates, Inc. ("Snavely King Majoros or SKM"). SKM is an economic consulting firm specializing in public utility and telecommunications costs and rates. Appendix A is a brief description of my qualifications and experience. It also contains a listing of my appearances before state and federal regulatory bodies. I am submitting this testimony on behalf of the North Dakota Public Service Commission ("NDPSC") Advocacy Staff

II. PURPOSE AND SUBJECT OF TESTIMONY

O. What is the purpose and subject of your testimony?

A. The North Dakota Public Service Commission Advocacy Staff ("Staff") retained SKM&A, Inc. to investigate a Northern States Power Company ("NSPS" or "Xcel") request for an Advance Determination of Prudence. My testimony addresses prudence from the customers' perspective. I focus on the Company's purchase price/cost economic analyses. My associate Paul Alvarez addresses prudence from an operational and planning standpoint.

III. QUALIFICATIONS

Q. What are your qualifications to present this testimony?

A. I have 40 years' experience in public utility field. I have testified on numerous utility accounting and ratemaking issues and I studied and debated the use of the customers' discount rate revenue requirement comparisons in a presentation to The Iowa State Regulatory Conference in 1986. Those comments are relevant in this proceeding. Also, my firm specializes in public utility depreciation. Our clients have ranged from consumer organizations and utility commissions to large companies that purchase regulated utility services. We have appeared as expert witnesses on depreciation before the regulatory commissions of more than half of the states in the country. I have testified in well over 100 proceedings on the subject of public utility depreciation. I have made several appearances in North Dakota. I have also negotiated on behalf of clients in fifteen of the Federal Communications Commission's ("FCC") triennial depreciation represcription conferences. Appendix A provides a summary of my qualifications and experience as well as a list of my appearances.

IV. SUMMARY OF COMPANY'S FILING

Q. Please summarize the Company's filing.

A. Northern States Power Company, doing business as Xcel Energy, requests an Advance Determination of Prudence for the Company to acquire from Southern Power Company:

- the Mankato Energy Center, LLC, which owns the existing 375 MW Mankato Energy Center (MEC I), and

- the Mankato Energy Center II, LLC, which owns the 345 MW expansion project (MEC II) scheduled to go in-service in June 2019.

The Application contains the supporting Direct Testimonies of Company witnesses Ms. Bria Shea and Mr. Philip Joseph Martin. Ms. Shea details the transaction and discusses the policy issues related to the matter and the prudence of the Company's request. Ms. Shae's testimony covers the following specific topics:

- Description and Purpose of the Acquisition;
- Regulatory Matters;
- Prudence of the Acquisition; and
- Presentation of Witnesses

Mr. Martin's testimony details the components and prudence of the purchase price and the economic analysis supporting the transaction. He concludes that the North Dakota Public Service Commission (Commission) should grant an advance determination of prudence (ADP) for the MEC I and MEC II transactions.[1] Mr. Martin's testimony covers the following specific topics:

- Purchase Price of the MEC Facility; and
- Economic Analysis of the Transaction.

V. STAFF'S 'S OBJECTIVES

Q. What are the Advocacy Staff's objectives in this proceeding?

A. Staff retained SKM to provide a thorough analysis of the advance prudence application, including the provision of written and oral testimony at the Commission's

[1] Martin Testimony (Martin), page 6.

technical hearing, and assistance in the preparation of pre- and post-hearing documents or possibly documents for purposes of moving to dismiss the application.

SKM understands that it must provide a detailed analysis and conclusion related to the *necessity* and the *economic prudence* of NSP's proposal to acquire the Mankato Energy Center I and II facilities.

Specifically the advocacy staff is interested in;

- determining the reasonableness of the Company's energy and demand forecasts,
- the costs of the two facilities,
- modeling inputs,
- sensitivity analysis,
- and the results as submitted by NSP.

VI. ANALYSIS OF STATUTORY REQUIREMENTS

Q. What are the statutory requirements controlling this issue?

A. The relevant enabling legislation is North Dakota Statute: 49-05-16 ("49-05-16") advance determination of prudence. The statute specifies:

- *resource addition* means construction, modification, purchase, or lease of an energy conversion facility, renewable energy facility, demand response system, transmission facility, or a contract to acquire energy, capacity, or demand response for the purpose of providing electric service.

- A public utility that intends to make a *resource addition* may file an application with the commission for an advance determination of prudence regarding the *resource addition. …*

- The commission may issue an order approving the prudence of a *resource addition if*:

  1. The public utility files with its application a projection of costs to the date of the anticipated commercial operation of the *resource addition*,

  2. The public utility files with its application a fee in the amount of one hundred seventy-five thousand dollars. …

  3. The commission provides notice and holds a hearing, if appropriate, in accordance with section 49-02-02; and

> 4. The commission determines that the *resource addition* is prudent. For facilities located or to be located in this state the commission, in determining whether the *resource addition* is prudent, shall consider the benefits of having the resource addition located in this state. …There is a rebuttable presumption that a resource addition located in the state is prudent."

Q. Does the filing involve a "resource addition" as defined by 49-05-16?

A. Yes.

Q. Does the filing contain a projection of costs through the anticipated commercial operation of the resource addition?

A. No, the Company provided a projection of the purchase price as of the June 2019 anticipated purchase date, but it did not provide a projection of the costs until after the purchase date. Those costs are based on the purchase price rather than the original cost as required by the FERC USOA.

Q. Is the resource addition located in North Dakota? If yes, what are the benefits of having the resource addition located in North Dakota?

A. No, it is located in Minnesota.

Q. Is the resource addition prudent as a result of the rebuttable presumption that it is prudent by virtue of being located in North Dakota?

A. No, the resource addition is not located in North Dakota.

VII. THE COST/PURECHASE PRICE OF THE TWO FACILITIES

Q. Mr. Martin states that "the total purchase price for this transaction is \$650 million, which is about \$100 million more than the present value of the Company's capacity payment obligations under the MEC I and MEC II power purchase agreements (PPAs)."[2] Have you investigated these statements?

A. Yes. The following tables summarize the information I have been able to glean about this purchase price.

[2] Martin page 3.

COST/PURCHASE INFORMATION
$millions

	$ Amount
<u>**Value of Capacity Payments on Existing PPAs 1/ [3]**</u>	
Capacity Payments on Existing PPA agreements	
for MEC I and II. 2018-2039	$927.8
2018 NPV	$569.9
Disaggregation of Purchase Price by Plant Function 1/	
[TRADE SECRET DATA BEGINS . . .	
Calculation Per DR 2-17 Attachment A	
Gross Cost of Plant	
Gross Cost of Plant in Service Production (MEC I and MEC II)	[redacted]
Gross Cost of Plant in Service Transmission (portion of MEC II expansion)	[redacted]
Total	[redacted]
Other Information Per DR 2-17 Attachment A	
MEC 1 COD	July 2017
MEC 1 Final Retirement Year	2046
MEC 1 life	40 yrs
MEC Expansion Final Retirement Year	2054
MEC II Expansion Life	35 yrs
. . . TRADE SECRET DATA ENDS]	
Calculation of Excess Purchase Price over PV of Existing PPAs	
Total Purchase Price (Martin, page 3.)	$650

[3] See responses to DR 1-3 and 2-12

PV of Company's Capacity Payments Under Relevant PPAs	($569.9)[4]
Excess Payment (Martin, page 3.)	$80.3

Calculation of Excess Purchase Price over Net Capitalized (Rate Base) Value of existing PPA's.

Total Purchase Price (Martin, page 3.)	$650
Rate Base Value of Existing PPAs (Response to 2-14 f., Attach. A. public document)	($223)
Excess Purchase Price	$427

[TRADE SECRET DATA BEGINS . . .

Q. What do you conclude from the information above?

A. I conclude that 2039 is the proper end point for PPA cost comparisons. I conclude that MEC I and MEC II production facilities purchase price is [redacted] million and that the MEC II costs include [redacted] million of additional transmission facilities. I also conclude that the Company expects to record a significant acquisition adjustment, but has not provided the anticipated amount.

. . . TRADE SECRET DATA ENDS]

Q. What was your primary objective regarding Cost/Purchase Price of the Mankato Energy Center?

A. My primary objective was to pin-down the original cost as required by the USOA and then conduct a recoverability assessment.

[4] Martin testimony, p. 3, lines 7-9 says "purchase price for this transaction is $650 million, which is about $100 million more than the present value of the Company's capacity payment obligations under the MEC I and MEC II power purchase agreements (PPAs)." This implies a $550 million present value of the PPAs. But see response to Staff 2-12 b. which references response to 1-3. The public version of the response to Staff 1-3 shows the 2018 NPV as $569.9 million; I note that the $569.9 amount contains 2018 numbers rather than starting with 2019. Or perhaps the difference is caused by a double-count of the initial year in the Company's present value formula.

Q. Why did you want to pin-down the cost as required by the USOA?

A. The existing PPAs are capital leases included in the Company's plant in service account 101.1-Property under capital leases.[5] It is reasonable to conclude that Xcel will attempt to include the MEC assets in plant-in-service. In addition, it seems clear to me that this transaction, if approved, is going to produce an acquisition adjustment. In order to know the amount of that adjustment it is necessary to know the original cost of these facilities when first devoted to public utility service.

Q. Did you pin down the original costs as required by the USOA?

A. No, the Company responded:

> Mankato Energy Center, LLC and Mankato Energy Center II, LLC sell wholesale power and services at market-based rates and are not required to file quarterly or annual FERC Form 1 or Form 3s, respectively.[6]
>
> Xcel Energy does not possess MEC I and MEC II facilities account and subaccount level accounting according to the FERC Uniform System of Accounts as of December 31, 2018.[7]

Q. Is it troubling that neither Southern Power Company nor Xcel have original cost amounts by USOA plant accounts?

A. Yes, it is troubling. Both of these companies have been in the electric business for a long time. Southern Power Company should have maintained its books at the USOA level regardless of selling wholesale power at market prices. *Original cost* is the foundation of utility accounting and I believe both companies know that fact. At this point, it seems to me that it is incumbent on Southern Power Company to conduct an original cost study before the transaction is closed. Furthermore, the prudence of the transaction is in question merely because we do not know the relevant numbers involved.

Q. What do the costs and information you summarized above reveal about this transaction?

A. The costs and information summarized above suggest that the $650 million purchase price is excessive.

[5] Response to Staff 2-14 f.

[6] Response to Staff 2-14 a.

[7] Id., b.

EXISTING PPAS AND TAX CUTS AND JOBS ACT ("TCJA")

Q. Do you have any conclusions about the $927.8 million of undiscounted capacity payments from the existing PPAs?[8]

A. Yes, the $927.8 million of undiscounted capacity payments is excessive.

Q. Why are the existing capacity payments excessive?

A. The existing capacity payments are excessive because they were developed at a time when the combined state and federal income tax was 41.37 percent but now the combined state and federal income tax rate is 28.774 percent.[9]

At page 6, Mr. Martin discusses how the TCJA "enhanced the value of power plants with PPA's in place" prior to the TCJA. Staff asked Mr. Martin whether the "TCJA enhanced the value of MEC 1 and MEC II." The Company responded:

> With a PPA in place at the time of the passage of TCJA, an IPP will not see their revenue from a project change after the reduction in corporate tax rates. This will increase the after tax profit due to the reduction in taxes payable for a given year. The increase in profitability is akin to an increase in cash flow, which drives an increase in valuation.[10]

Q. How is that enhanced value reflected in the Company's filing?

A. The enhanced value shows up as either excessive PPA revenues or an excessive purchase price or a combination of both. Staff asked the company to describe whether and how it took the likely impact of the TCJA into account when evaluating the cost alternatives to the MEC I and MEC II purchase.[11] The Company responded that:

> All assessments of the MEC I and MEC II purchase were performed using post TCJA federal tax rates as that law was in effect at the time of our acquisition.[12]

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[8] Response to Staff 1-3.
[9] Response to Staff 2-13. Public version.
[10] Id.
[11] Response to 2-5 b.
[12] Id.

Q. Did the Company take into account the likely impact of the TCJA on future PPA prices when evaluating the cost of alternatives to the MEC I and MEC II purchase?[13]

A. The Company stated:

> We did not model future PPA prices in our assessment of the Mankato acquisition beyond that used in our Strategist models, which used generic costs for replacement generation in choosing the most economic resource mix.[14]

The Company also stated:

> The Company does not speculate on the pricing and/or terms of a specific PPA extension as it is impossible to know for sure how negotiations with a counterparty may unfold. As a result, we did not create any analysis forecasting the cost of a replacement PPA. However, our Strategist modeling in our status quo scenario with no Mankato acquisition, when the PPA expires, the model replaces the lost energy with either energy from a different resource in our portfolio or MISO market purchases (whichever is cheaper).[15]

Q. Could the Company restructure its existing PPAs to adjust for the effect of the TCJA?

A. I think the Company should be able to restructure the PPAs given the magnitude of the TCJA on costs. The Company states:

> To the extent an IPP with a current contract to sell power to NSPM would be willing to lower pricing of a contract due to a change in their tax position, <u>restructuring the PPA may be possible</u>.[16]

Q. But if the Company does not purchase MEC I and MEC II will it in fact renegotiate the existing PPAs to adjust for the TCJA?

A. No. The Company states:

[13] Response to 2-5c.
[14] Id.
[15] Response to 2-4.
[16] Response to 2-5 d. (emphasis added)

> Both the MEC I and MEC II [PPA] contracts are in full force and effect and we do not foresee a renegotiation as described.[17]

Q. What are the practical consequences of that decision?

A. The Company will not renegotiate the excessive PPA prices to adjust for the TCJA. This decision makes the Company's Mankato purchase price appear more favorable to the Company.

VIII. REASONABLENESS OF COMPANY'S ENERGY AND DEMAND FORECASTS.

Q. Did you specifically address the Company's energy and demand forecasts?

A. Mr. Alvarez conducted those analyses.

Q. What did Mr. Alvarez conclude?

A. Based on recent historical actuals and industry-wide trends, Mr. Alvarez believes that the Company's energy and demand forecasts are unreasonably high. He also believes that the Company's generation capacity forecasts were unreasonably low, as they assume an unlikely closure of the Company's nuclear unit capacity from 2031-2034. Combined, Mr. Alvarez concluded that the capacity from MEC I & II is unlikely to be needed in a timeframe early enough in the MEC I & II lifetimes to deliver benefits to customers in excess of costs if purchased.

X. ECONOMIC ANALYSIS

Q. Please explain Mr. Martin's economic analysis.

A. Mr. Martin's testimony discusses the "Company's proposed acquisition of the … MEC Facility that is scheduled to go in-service in June of 2019. He discusses "the components and prudence of the purchase price and the economic analysis supporting the transaction."[18]

Q. What does Mr. Martin conclude as a result of his economic analysis?

A. He concluded "that the proposed transaction is cost effective, with overall system costs being lowered, on a present value of revenue requirement basis, over the life of the MEC facility with Company ownership than without it."(sic)[19]

[17] Response to 2-5 e.
[18] Martin p. 2.
[19] Martin, p.6 lines 25-26.

Q. Do you agree with Mr. Martin's conclusions?

A. I could only agree with Mr. Martin's conclusions if I agreed with the process, assumptions and inputs he used to conduct his net present value of revenue requirements ("NPVRR") analyses. However, I disagree agree with several of his fundamental assumptions and as a result, I do not think the transaction is cost effective from the Company's ratepayers' perspective.

Q. Mr. Martin states that he used Strategist software to analyze several scenarios concerning the Company's proposed integration of Mankato resources into the overall NSP system.[20] Do you agree with that statement?

A. I accept Mr. Martin's statement at face value. For each scenario Mr. Martin modeled the system net present value of the expected revenue requirements with and without Mankato ownership from 2018 to 2057.[21] In other words, the "with" scenario was total system costs assuming ownership through 2057 and the cessation of the existing MEC PPAs and the "without" scenario was total system costs assuming continuation of the existing MEC PPAs.[22] He focused on two primary planning assumptions: the Modified IRP Plan and the 85-30 Plan. Next he assumed the difference between the two runs for both planning scenarios represents the incremental annual revenue requirement impact resulting from the Mankato purchase.

Q. What were Mr. Martin's results?

A. Mr. Martin's Table 1 shows:

Mr. Martin's Table 1[23]
Overall PVRR Savings shows:

Modified IRP Scenario	$142 million
85-by-30 Scenario	$66 million

Q. Does Mr. Martin base his entire economic justification on these two streams of numbers?

A. Yes.

[20] Martin p.6 and 7.
[21] Martin p.13
[22] Martin p.6, lines 17-21.
[23] Martin p.7

[TRADE SECRET DATA BEGINS . . .

Q. Can you explain Mr. Martin's results in more detail?

A. Yes. Mr. Martin summarized two streams of annual system revenue requirements in nominal dollars through 2057 for each scenario above, i.e. four runs in total. They were labeled "Base" and "Own" where Base assumed the business as usual series and Own assumed the Company purchased the Mankato Energy Center. Next, he calculated the net present value of each stream at a 6.53 percent discount rate to arrive at the results below.[24]

Mr. Martin's NPVRR Results [25]
Discounted at 6.53% through 2057
$millions

	Base	Own	Savings
Modified IRP Base	[redacted]		
85-by-30	[redacted]		

Q. What facts can you glean by examining Mr. Martin's revenue requirement streams?

A. First, in each case, the undiscounted revenue requirements generally increase through the 2030s before they start a long-term decline. In each case, it takes several years for ratepayers to break even from the revenue requirement increases in the early years.

The maximum cumulative increases to ratepayers are:

Maximum Cumulative Increase to Ratepayers
And Breakeven Year
$millions

	Amount	Breakeven Year
Modified IRP Base	[redacted]	
85-by-30	[redacted]	

From a revenue requirement standpoint, ratepayers are in a worse position for at least 14 years and as many as 24 years depending upon which scenario is adopted.

[24] Response to 2-17, Attachments A,B,C.
[25] Id. Not Public Document

. . . TRADE SECRET DATA ENDS]

Q. Do you agree with the periods Mr. Martin used in his models?

A. No, Mr. Martin's models compare revenue requirement streams for the entire period of the Mankato II life. But this period extends far beyond the PPA end dates. At a maximum, he should only have modeled the period between 2019 and 2039, the end of the MEC II PPA. That is 21 years rather than 36 years. Even the Company recognizes that 2039 should be end point of the comparison as I discussed earlier.[26] The 2057 end point is unreasonable.

Q. Are there any other reasons Mr. Martin's results are unreasonable?

A. Yes. Mr. Martin's models present a choice—should ratepayers absorb the costs of the Mankato purchase or should the Company retain the status quo as reflected by a continuation of the existing PPA's? Mr. Martin concludes that the answer is yes – ratepayers should absorb the cost of the Mankato purchase, based on his net present value analysis of the two competing streams of charges to ratepayers discounted at 6.53 percent.[27]

[TRADE SECRET DATA BEGINS . . .

Q. What is the source of the Company's 6.53 percent discount rate?

A. It is the Company's calculation of the [redacted].[28]

. . . TRADE SECRET DATA ENDS]

Q. Do you agree with the Company's 6.53 percent discount rate?

A. No. The Company's 6.53 percent discount rate is inappropriate for use in a model comparing streams of charges to ratepayers. The 6.53 percent represents the Company's discount rate rather than its ratepayers' discount rate.

[26] Response to Staff 1-3.
[27] Exhibit____(PJM-), Schedule 1.
[28] Response to 2-17 Attach. A

VI. RATEPAYERS' DISCOUNT RATE

Q. Please explain the concept of the ratepayers' discount rate.

A. Since I am addressing prudence from the customers' perspective, it is important to understand the concept of the ratepayers' or customers' discount rate. I initially debated the concept at the 25th Annual Iowa State Regulatory Conference in 1986: the subject was "The Use of Customer Discount Rates in Revenue Requirement Comparisons."

Q. Do you have a copy of your presentation to the 1986 Iowa State regulatory conference?

A. Yes, Exhibit___ (MJM-1) is a copy of the presentation. It was presented as a speech within the context of a debate. I have corrected a few typographical and grammatical errors.

Q. Why is the customers' discount relevant in this proceeding

A. The customer's discount rate is relevant because Xcel has presented a comparison of revenue requirement streams which allegedly demonstrate a customer savings from its proposed purchase of the Mankato Energy Center using a NPVRR approach to the analysis.[29] Xcel used a 6.53 percent discount rate, which is an after-tax cost of capital rate. However, its ratepayers' discount rates are far different than a regulated monopoly's discount rate.

Q. What is a discount rate?

A. A discount rate is a compound interest factor used to determine the net present value of a stream of future cash flows. It embodies the user's time preference, inflation and risk expectations. When a utility evaluates new investments, it must assume they are as risky as current investments such as embedded plant; hence, the utility's discount rate is its cost of capital.

Q. What is a customer discount rate?

A. Xcel has two broad classes of customers – individuals and firms. A firm's discount rate is hypothetically derived much the same way as is Xcel's cost of capital, that is, through an analysis of the composite effect of business and financial risk. Large heavily-capitalized customers will likely have composite risk factors quite similar to that of utilities. Smaller firms, however, particularly those with limited capitalization - like mine for example - have a higher cost of capital and hence, higher discount rates than the utility that serves them.

[29] Martin page 6.

Q. What about the individual customer's discount rate?

A. The individual's discount rates vary significantly; there is no single rate. At one extreme, there are consumers living at or below the poverty level. For these people with no discretionary income at all, the discount rate is prohibitive because deferral of a single dollar of income to pay for Xcel's new plant will deprive that customer of one of the basic necessities of life: food, clothing, or shelter. As income increases, the opportunity cost of the incremental dollar falls. For low-to-moderate income customers, who are likely to be net debtors, the discount rate is represented by the finance charge rate on consumer credit, which can be 18 percent or higher. At the high end of the income spectrum, the discount rate is equivalent to the marginal return from individual investments – stocks, bonds, real estate, tax shelters. Therefore, the customers' discount rate is not equal to the utility's cost of capital, and for most customers here in North Dakota, and elsewhere throughout this country, it is substantially higher. The North Dakota customers most hurt by a rate increase are those with the highest personal discount rates—those in the individual and small business rate classes.

Q. Your speech to the Iowa State Regulatory conference says it is "arguably impossible to determine a composite individual and small firm discount rate." Do you still believe it is arguably impossible?

A. Someone might argue that it is impossible, but over the last 32 years since 1986 I have learned that almost nothing is impossible, so that person will not be me.

Q. Is it impossible to estimate a single customer's discount rate?

A. No, it would be quite simple. For example, one could assign a reasonably estimated consumer discount rate to different classes of customers and then calculate a direct-weighted value. Alternatively, one could judgmentally select a number that most reasonable people would agree is representative of a majority of customers, as I did in the Iowa State presentation examples.

Q. Does the North Dakota statute recognize the concept of the customers' discount rate in prudence determinations?

A. I believe it does. Statute 49-05-16 describes the factors which shall be considered by the commission in making the determination of "prudence" or lack thereof. The Company's demonstration of economic prudence in this proceeding consists of a comparison of revenue streams that can only be rationalized on a discounted basis using a discount factor that does not represent its customer's interests.

Q. Is it your testimony that the provisions summarized above constitute statutory recognition of the concept of the customer's discount rate and its use in prudence determinations?

A. Yes.

Q. How so?

A. Consider how the Commission can measure the interests of the people of North Dakota or the interests of Xcel's customers in a prudence proceeding. The Commission may issue an order approving the prudence of a *resource addition if*: the commission determines that the *resource addition* is prudent. The Commission must have a hearing at which I assume the Company has the obligation to demonstrate that the resource addition is prudent since an imprudent resource addition would overcharge customers. Obviously, the impact on customers' rates is at the heart of such demonstrations. This statute is clearly contemplating an analysis of the impact on customers. Recognizing the customers' discount rate is a valid way to analyze the impact on them. When one is going to analyze the adverse economic impact on the people of North Dakota, consideration of the customer's discount rate is not only appropriate, but is necessary.

Q. Is this a legal opinion?

A. No. I have raised the customer discount rate issue here because it is applicable. It should be addressed here regardless of any other showings the company must make to support a prudence claim.

Q. Did Xcel properly consider the interests of the people of North Dakota in its studies?

A. No. Xcel conducted revenue requirement comparisons that considered only the people and businesses at the high end of the food chain, it failed to evaluate the adverse consequences of its proposals not only on the poor and middle class people of North Dakota who will pay the bulk of the cost, but on the public interest in general.

Q. Have you estimated the ratepayers' discount rate for the purposes of this proceeding?

A. Yes, below is my estimate of the ratepayers' discount rate for the purposes of this proceeding. Currently, 17 percent is the average interest rate Americans pay their banks on credit cards.[30] It is an average because it relates to the spectrum from wealthy who may pay less than 17 percent to poor individuals who obviously pay more than 17 percent. Consequently, I used the 17

[30] See Exhibit___(MJM-2)

percent average for Residential and Non-Demand customers and the Company's 6.53 percent for its Demand customers. I obtained the Company's 2015 revenues for its North Dakota customers and then calculated the weighted average ratepayer discount rate. The weighted average ratepayer discount rate is 11.27 percent.

Weighted Average Ratepayer Discount Rate based of 2015 North Dakota Revenues
$ millions

	Revenues	Interest Rate
Residential and Non-DMD.	$96, 907	17.00 %
Demand	$117,189	6.53%
Weighted Average Discount Rate		11.27%

Q. Have you conducted a NPVRR calculation using the 11.27 percent ratepayer discount rate?

A. Yes, I have conducted two NPVRR analyses using the 11.27 percent for each of the Company's scenarios. One version of the analysis uses the same period as the Company, that is until 2057 - the end of MEC IIs life. The other version ended the comparison when the combined PPAs run out in 2039.

The table below summarizes my results and compares them to Mr. Martin's. Using the same period as Mr. Martin and a 11.27 percent ratepayer discount rate, the Modified IRP NPVRR savings shrink from $142 million to $44 million and when the period is adjusted to end when the combined PPAs end, the savings shrink even further to $14 million. Similarly, the 85-by-30 NPVRR savings shrink from $66 million to an $7 million additional cost and then to a $46 million additional cost.

Overall NPVRR Savings:
$millions

	Martin	SKM	SKM
	6.53%-2057	**11.27%-2057**	**11.27%-2039**
Modified IRP Scenario	$142	$44	$14
85-by-30 Scenario	$66	-$7	-$46

Q. What do you conclude from this analysis?

A. I conclude that any NPVRR savings from this potential acquisition are negligible at best and are not in the ratepayers' best economic interests particularly given the front-loading and breakeven points discussed earlier.

TRADITIONAL BUY VS. LEASE ANALYSIS

Q. Your discussion above relates primarily to prudency from the customers' perspective and involves the Company's system-level Strategist summaries. However, were you able to determine if the Company conducted a stand-alone lease vs. buy analysis comparing the discrete revenue requirements (costs) resulting from the Mankato purchase v. the costs of continuing the existing PPAs?

A. In data request 2-20 we asked the Company to "provide a standalone sensitivity comparing the standalone MEC purchases compared to the MEC I and II PPAs."[31] Subsequently we clarified the request as follows:

> At page 6 of his testimony, Mr. Martin states,
>
> "For this analysis, the Company simulated the operation of the NSP System through 2057 and compared system costs of Company ownership of the MEC Facility to system costs when the output of the MEC Facility is purchased under the existing PPAs."
>
> Question 2-20 is asking for a comparison of the discrete (not system) MEC Purchase Cost versus the discreet (not system) PPA costs.

The Company responded "Please see our response to NDPSC DR No. 2-17."[32]

Q. Did the response to NDPSC DR No. 2-17 provide the information you requested?

A. The response to that data request provided a portion of the information requested, but not all. Attachment A to its response to NDPSC No. 2-17 provided the annual revenue requirements associated with the purchase of the Mankato Energy Center, but it did not provide the costs associated with a continuation of the existing PPAs. Consequently, I had to look elsewhere for those costs. I found them in the Company's response to Staff DR No. 1-3, i.e. the capacity payments on the existing PPA agreements for MEC I and II.

[31] Staff DR No. 2-20.

[32] Response to Staff 2-20.

Q. Were you able to use that data to conduct standalone lease v. buy analyses relating to the Company's proposed purchase?

A. Yes. I would characterize these analyses as ones that would have been made in a competitive environment in which the Company did not have captive ratepayers to pay for excess costs. I have retained the Company's nomenclature for the assumptions: Base means a continuation of the existing PPAs, and Own means purchase the Mankato Energy Center.

Q. What discount rate did you use in these analyses?

A. I used the Company's proposed discount rate. Since these analyses assume a competitive market without captive ratepayers, I did not use the customers' discount rate.

Q. What were your results?

[TRADE SECRET DATA BEGINS . . .

A. The MEC I PPA ends in 2027 and the MEC II PPA ends in 2039. My first Standalone analysis ended the comparison at the end of 2027. The net present value of the Own assumption was [redacted] million and the net present value of the Base assumption was [redacted] million. In other words the Own assumption is [redacted] million less economic than the Base assumption.

My next Standalone analysis ended the comparison at the end of 2039, which is the year when the existing MEC II PPA expires. It also assumes that the existing MEC I PPA expired in 2027 without any replacement. In my opinion, this is the decision with which the Company is actually confronted. The net present value of the Base assumption was [redacted] million and the net present value of the Own decision was [redacted] million. Again, the Own assumption is more expensive than the Base assumption.

My final standalone analysis ends in 2039, but I have assumed the Company renegotiated the MEC I PPA and that it too continued to 2039 to expire simultaneously with the MEC II PPA. The net present value of the Own assumption was [redacted] million and the net present values of the Base assumption was [redacted] million; again Own is more expensive.

As a final run, I ran the net present value of the Own revenue requirements through 2054 which is the end point in the Company's analyses. The net present value of the 2019 to 2054 Own assumption is [redacted] million which far surpasses the cost of any version of the Base assumption.

. . . TRADE SECRET DATA ENDS]

Q. What do you conclude?

A. I conclude that a competitive company would not purchase the Mankato Energy Center at this point. It is not economic. The only thing that makes this economic from the Xcel's standpoint is the fact that it has captive customers who will be required to pay for this bad deal.

Q. Does this conclude your testimony.

A. Yes, it does.

Experience

Analytica94, Inc.
Chairman and Founder (2013 to present)

A94 is a chartable non-profit organization founded in 2013 to provide independent research, economic models, and training to evaluate the effectiveness of economic regulation of U.S. industries.

Snavely King Majoros & Associates, Inc.
President (2010 to present)
Vice President and Treasurer (1988 to 2010)
Senior Consultant (1981-1987)

Mr. Majoros provides consultation specializing in accounting, financial, and management issues. He has testified as an expert witness or negotiated on behalf of clients in more than one hundred thirty regulatory federal and state regulatory proceedings involving telephone, electric, gas, water, and sewerage companies. His testimony has encompassed a wide array of complex issues including taxation, divestiture accounting, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. Mr. Majoros has also provided consultation to the U.S. Department of Justice and appeared before the U.S. EPA and the Maryland State Legislature on matters regarding the accounting and plant life effects of electric plant modifications and the financial capacity of public utilities to finance environmental controls. He has estimated economic damages suffered by black farmers in discrimination suits.

Van Scoyoc & Wiskup, Inc., *Consultant (1978-1981)*

Mr. Majoros conducted and assisted in various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems; preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission; accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities. Mr. Majoros provided onsite management accounting and controllership assistance to a municipal electric and water utility. Mr. Majoros also assisted in an antitrust proceeding involving a major electric utility. He submitted expert testimony in FERC Docket No. RP79-12 (El Paso Natural Gas Company), and he co-authored a study entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No. RM 80-42.

Handling Equipment Sales Company, Inc.
Controller/Treasurer (1976-1978)

Mr. Majoros' responsibilities included financial management, general accounting and reporting, and income taxes.

Ernst & Ernst, *Auditor (1973-1976)*

Mr. Majoros was a member of the audit staff where his responsibilities included auditing, supervision, business systems analysis, report preparation, and corporate income taxes.

University of Baltimore - *(1971-1973)*

Mr. Majoros was a full-time student in the School of Business.

During this period Mr. Majoros worked consistently on a part-time basis in the following positions: Assistant Legislative Auditor – State of Maryland, Staff Accountant – Robert M. Carney & Co., CPA's, Staff Accountant – Naron & Wegad, CPA's, Credit Clerk – Montgomery Wards.

Central Savings Bank, *(1969-1971)*

Mr. Majoros was an Assistant Branch Manager at the time he left the bank to attend college as a full-time student. During his tenure at the bank, Mr. Majoros gained experience in each department of the bank. In addition, he attended night school at the University of Baltimore.

Education
University of Baltimore, School of Business, B.S. –
Concentration in Accounting

Professional Affiliations
American Institute of Certified Public Accountants
Maryland Association of C.P.A.s
Society of Depreciation Professionals

Publications, Papers, and Panels

"Analysis of Staff Study on Comprehensive Tax Normalization," FERC Docket No. RM 80-42, 1980.

"Telephone Company Deferred Taxes and Investment Tax Credits – A Capital Loss for Ratepayers," Public Utility Fortnightly, September 27, 1984.

"The Use of Customer Discount Rates in Revenue Requirement Comparisons," Proceedings of the 25th Annual Iowa State Regulatory Conference, 1986

"The Regulatory Dilemma Created By Emerging Revenue Streams of Independent Telephone Companies," Proceedings of NARUC 101st Annual Convention and Regulatory Symposium, 1989.

"BOC Depreciation Issues in the States," National Association of State Utility Consumer Advocates, 1990 Mid-Year Meeting, 1990.

"Current Issues in Capital Recovery" 30th Annual Iowa State Regulatory Conference, 1991.

"Impaired Assets Under SFAS No. 121," National Association of State Utility Consumer Advocates, 1996 Mid-Year Meeting, 1996.

"What's 'Sunk' Ain't Stranded: Why Excessive Utility Depreciation is Avoidable," with James Campbell, Public Utilities Fortnightly, April 1, 1999.

"Local Exchange Carrier Depreciation Reserve Percents," with Richard B. Lee, Journal of the Society of Depreciation Professionals, Volume 10, Number 1, 2000-2001

"Rolling Over Ratepayers," Public Utilities Fortnightly, Volume 143, Number 11, November, 2005.

"Asset Management – What is it ?" American Water Works Association, Pre-Conference Workshop, March 25, 2008.

"Main Street Gold Mine," with Dr. K. Pavlovic and J. Legieza, Public Utilities Fortnightly, October, 2010

Appendix A

Michael J. Majoros, Jr.

Date	Jurisdiction / Agency	Docket	Utility

Federal Courts

2005	US District Court, Northern District of AL, Northwestern Division 55/56/57/	CV 01-B-403-NW	Tennessee Valley Authority

State Legislatures

2006	Maryland General Assembly 61/	SB154	Maryland Healthy Air Act
2006	Maryland House of Delegates 62/	HB189	Maryland Healthy Air Act

Federal Regulatory Agencies

1979	FERC-US 19/	RP79-12	El Paso Natural Gas Co.
1980	FERC-US 19/	RM80-42	Generic Tax Normalization
1996	CRTC-Canada 30/	97-9	All Canadian Telecoms
1997	CRTC-Canada 31/	97-11	All Canadian Telecoms
1999	FCC 32/	98-137 (Ex Parte)	All LECs
1999	FCC 32/	98-91 (Ex Parte)	All LECs
1999	FCC 32/	98-177 (Ex Parte)	All LECs
1999	FCC 32/	98-45 (Ex Parte)	All LECs
2000	EPA 35/	CAA-00-6	Tennessee Valley Authority
2003	FERC 48/	RM02-7	All Utilities
2003	FCC 52/	03-173	All LECs
2003	FERC 53/	ER03-409-000, ER03-666-000	Pacific Gas and Electric Co.
2017	FERC 53/	ER16-2320-002	Pacific Gas and Electric Company

State Regulatory Agencies

1982	Massachusetts 17/	DPU 557/558	Western Mass Elec. Co.
1982	Illinois 16/	ICC81-8115	Illinois Bell Telephone Co.
1983	Maryland 8/	7574-Direct	Baltimore Gas & Electric Co.
1983	Maryland 8/	7574-Surrebuttal	Baltimore Gas & Electric Co.
1983	Connecticut 15/	810911	Woodlake Water Co.
1983	New Jersey 1/	815-458	New Jersey Bell Tel. Co.
1983	New Jersey 14/	8011-827	Atlantic City Sewerage Co.
1984	Dist. Of Columbia 7/	785	Potomac Electric Power Co.
1984	Maryland 8/	7689	Washington Gas Light Co.
1984	Dist. Of Columbia 7/	798	C&P Tel. Co.
1984	Pennsylvania 13/	R-832316	Bell Telephone Co. of PA

Michael J. Majoros, Jr.

1984	New Mexico 12/	1032	Mt. States Tel. & Telegraph
1984	Idaho 18/	U-1000-70	Mt. States Tel. & Telegraph
1984	Colorado 11/	1655	Mt. States Tel. & Telegraph
1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co.
1984	Pennsylvania 3/	R842621-R842625	Western Pa. Water Co.
1985	Maryland 8/	7743	Potomac Edison Co.
1985	New Jersey 1/	848-856	New Jersey Bell Tel. Co.
1985	Maryland 8/	7851	C&P Tel. Co.
1985	California 10/	I-85-03-78	Pacific Bell Telephone Co.
1985	Pennsylvania 3/	R-850174	Phila. Suburban Water Co.
1985	Pennsylvania 3/	R850178	Pennsylvania Gas & Water Co.
1985	Pennsylvania 3/	R-850299	General Tel. Co. of PA
1986	Maryland 8/	7899	Delmarva Power & Light Co.
1986	Maryland 8/	7754	Chesapeake Utilities Corp.
1986	Pennsylvania 3/	R-850268	York Water Co.
1986	Maryland 8/	7953	Southern Md. Electric Corp.
1986	Idaho 9/	U-1002-59	General Tel. Of the Northwest
1986	Maryland 8/	7973	Baltimore Gas & Electric Co.
1987	Pennsylvania 3/	R-860350	Dauphin Cons. Water Supply
1987	Pennsylvania 3/	C-860923	Bell Telephone Co. of PA
1987	Iowa 6/	DPU-86-2	Northwestern Bell Tel. Co.
1987	Dist. Of Columbia 7/	842	Washington Gas Light Co.
1988	Florida 4/	880069-TL	Southern Bell Telephone
1988	Iowa 6/	RPU-87-3	Iowa Public Service Company
1988	Iowa 6/	RPU-87-6	Northwestern Bell Tel. Co.
1988	Dist. Of Columbia 7/	869	Potomac Electric Power Co.
1989	Iowa 6/	RPU-88-6	Northwestern Bell Tel. Co.
1990	New Jersey 1/	1487-88	Morris City Transfer Station
1990	New Jersey 5/	WR 88-80967	Toms River Water Company
1990	Florida 4/	890256-TL	Southern Bell Company
1990	New Jersey 1/	ER89110912J	Jersey Central Power & Light
1990	New Jersey 1/	WR90050497J	Elizabethtown Water Co.
1991	Pennsylvania 3/	P900465	United Tel. Co. of Pa.
1991	West Virginia 2/	90-564-T-D	C&P Telephone Co.
1991	New Jersey 1/	90080792J	Hackensack Water Co.
1991	New Jersey 1/	WR90080884J	Middlesex Water Co.
1991	Pennsylvania 3/	R-911892	Phil. Suburban Water Co.
1991	Kansas 20/	176, 716-U	Kansas Power & Light Co.
1991	Indiana 29/	39017	Indiana Bell Telephone
1991	Nevada 21/	91-5054	Central Tele. Co. – Nevada
1992	New Jersey 1/	EE91081428	Public Service Electric & Gas
1992	Maryland 8/	8462	C&P Telephone Co.

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1992	West Virginia 2/	91-1037-E-D	Appalachian Power Co.
1993	Maryland 8/	8464	Potomac Electric Power Co.
1993	South Carolina 22/	92-227-C	Southern Bell Telephone
1993	Maryland 8/	8485	Baltimore Gas & Electric Co.
1993	Georgia 23/	4451-U	Atlanta Gas Light Co.
1993	New Jersey 1/	GR93040114	New Jersey Natural Gas. Co.
1994	Iowa 6/	RPU-93-9	U.S. West – Iowa
1994	Iowa 6/	RPU-94-3	Midwest Gas
1995	Delaware 24/	94-149	Wilm. Suburban Water Corp.
1995	Connecticut 25/	94-10-03	So. New England Telephone
1995	Connecticut 25/	95-03-01	So. New England Telephone
1995	Pennsylvania 3/	R-00953300	Citizens Utilities Company
1995	Georgia 23/	5503-0	Southern Bell
1996	Maryland 8/	8715	Bell Atlantic
1996	Arizona 26/	E-1032-95-417	Citizens Utilities Company
1996	New Hampshire 27/	DE 96-252	New England Telephone
1997	Iowa 6/	DPU-96-1	U S West – Iowa
1997	Ohio 28/	96-922-TP-UNC	Ameritech – Ohio
1997	Michigan 28/	U-11280	Ameritech – Michigan
1997	Michigan 28/	U-112 81	GTE North
1997	Wyoming 27/	7000-ztr-96-323	US West – Wyoming
1997	Iowa 6/	RPU-96-9	US West – Iowa
1997	Illinois 28/	96-0486-0569	Ameritech – Illinois
1997	Indiana 28/	40611	Ameritech – Indiana
1997	Indiana 27/	40734	GTE North
1997	Utah 27/	97-049-08	US West – Utah
1997	Georgia 28/	7061-U	BellSouth – Georgia
1997	Connecticut 25/	96-04-07	So. New England Telephone
1998	Florida 28/	960833-TP et. al.	BellSouth – Florida
1998	Illinois 27/	97-0355	GTE North/South
1998	Michigan 33/	U-11726	Detroit Edison
1999	Maryland 8/	8794	Baltimore Gas & Electric Co.
1999	Maryland 8/	8795	Delmarva Power & Light Co.
1999	Maryland 8/	8797	Potomac Edison Company
1999	West Virginia 2/	98-0452-E-GI	Electric Restructuring
1999	Delaware 24/	98-98	United Water Company
1999	Pennsylvania 3/	R-00994638	Pennsylvania American Water
1999	West Virginia 2/	98-0985-W-D	West Virginia American Water
1999	Michigan 33/	U-11495	Detroit Edison
2000	Delaware 24/	99-466	Tidewater Utilities
2000	New Mexico 34/	3008	US WEST Communications, Inc.
2000	Florida 28/	990649-TP	BellSouth -Florida

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2000	New Jersey 1/	WR30174	Consumer New Jersey Water
2000	Pennsylvania 3/	R-00994868	Philadelphia Suburban Water
2000	Pennsylvania 3/	R-0005212	Pennsylvania American Sewerage
2000	Connecticut 25/	00-07-17	Southern New England Telephone
2001	Kentucky 36/	2000-373	Jackson Energy Cooperative
2001	Kansas 38/39/40/	01-WSRE-436-RTS	Western Resources
2001	South Carolina 22/	2001-93-E	Carolina Power & Light Co.
2001	North Dakota 37/	PU-400-00-521	Northern States Power/Xcel Energy
2001	Indiana 29/41/	41746	Northern Indiana Power Company
2001	New Jersey 1/	GR01050328	Public Service Electric and Gas
2001	Pennsylvania 3/	R-00016236	York Water Company
2001	Pennsylvania 3/	R-00016339	Pennsylvania America Water
2001	Pennsylvania 3/	R-00016356	Wellsboro Electric Coop.
2001	Florida 4/	010949-EL	Gulf Power Company
2001	Hawaii 42/	00-309	The Gas Company
2002	Pennsylvania 3/	R-00016750	Philadelphia Suburban
2002	Nevada 43/	01-10001 &10002	Nevada Power Company
2002	Kentucky 36/	2001-244	Fleming Mason Electric Coop.
2002	Nevada 43/	01-11031	Sierra Pacific Power Company
2002	Georgia 27/	14361-U	BellSouth-Georgia
2002	Alaska 44/	U-01-34,82-87,66	Alaska Communications Systems
2002	Wisconsin 45/	2055-TR-102	CenturyTel
2002	Wisconsin 45/	5846-TR-102	TelUSA
2002	Vermont 46/	6596	Citizen's Energy Services
2002	North Dakota 37/	PU-399-02-183	Montana Dakota Utilities
2002	Kansas 40/	02-MDWG-922-RTS	Midwest Energy
2002	Kentucky 36/	2002-00145	Columbia Gas
2002	Oklahoma 47/	200200166	Reliant Energy ARKLA
2002	New Jersey 1/	GR02040245	Elizabethtown Gas Company
2003	New Jersey 1/	ER02050303	Public Service Electric and Gas Co.
2003	Hawaii 42/	01-0255	Young Brothers Tug & Barge
2003	New Jersey 1/	ER02080506	Jersey Central Power & Light
2003	New Jersey 1/	ER02100724	Rockland Electric Co.
2003	Pennsylvania 3/	R-00027975	The York Water Co.
2003	Pennsylvania 3/	R-00038304	Pennsylvania-American Water Co.
2003	Kansas 20/ 40/	03-KGSG-602-RTS	Kansas Gas Service
2003	Nova Scotia, CN 49/	EMO NSPI	Nova Scotia Power, Inc.
2003	Kentucky 36/	2003-00252	Union Light Heat & Power
2003	Alaska 44/	U-96-89	ACS Communications, Inc.
2003	Indiana 29/	42359	PSI Energy, Inc.
2003	Kansas 20/ 40/	03-ATMG-1036-RTS	Atmos Energy
2003	Florida 50/	030001-E1	Tampa Electric Company

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2003	Maryland 51/	8960	Washington Gas Light
2003	Hawaii 42/	02-0391	Hawaiian Electric Company
2003	Illinois 28/	02-0864	SBC Illinois
2003	Indiana 28/	42393	SBC Indiana
2004	New Jersey 1/	ER03020110	Atlantic City Electric Co.
2004	Arizona 26/	E-01345A-03-0437	Arizona Public Service Company
2004	Michigan 27/	U-13531	SBC Michigan
2004	New Jersey 1/	GR03080683	South Jersey Gas Company
2004	Kentucky 36/	2003-00434,00433	Kentucky Utilities, Louisville Gas & Electric
2004	Florida 50/ 54/	031033-EI	Tampa Electric Company
2004	Kentucky 36/	2004-00067	Delta Natural Gas Company
2004	Georgia 23/	18300, 15392, 15393	Georgia Power Company
2004	Vermont 46/	6946, 6988	Central Vermont Public Service Corporation
2004	Delaware 24/	04-288	Delaware Electric Cooperative
2004	Missouri 58/	ER-2004-0570	Empire District Electric Company
2005	Florida 50/	041272-EI	Progress Energy Florida, Inc.
2005	Florida 50/	041291-EI	Florida Power & Light Company
2005	California 59/	A.04-12-014	Southern California Edison Co.
2005	Kentucky 36/	2005-00042	Union Light Heat & Power
2005	Florida 50/	050045 & 050188-EI	Florida Power & Light Co.
2005	Kansas 38/ 40/	05-WSEE-981-RTS	Westar Energy, Inc.
2006	Delaware 24/	05-304	Delmarva Power & Light Company
2006	California 59/	A.05-12-002	Pacific Gas & Electric Co.
2006	New Jersey 1/	GR05100845	Public Service Electric and Gas Co.
2006	Colorado 60/	06S-234EG	Public Service Co. of Colorado
2006	Kentucky 36/	2006-00172	Union Light, Heat & Power
2006	Kansas 40/	06-KGSG-1209-RTS	Kansas Gas Service
2006	West Virginia 2/	06-0960-E-42T, 06-1426-E-D	Allegheny Power
2006	West Virginia 2/	05-1120-G-30C, 06-0441-G-PC, et al.	Hope Gas, Inc. and Equitable Resources, Inc.
2007	Delaware 24/	06-284	Delmarva Power & Light Company
2007	Kentucky 36/	2006-00464	Atmos Energy Corporation
2007	Colorado 60/	06S-656G	Public Service Co. of Colorado
2007	California 59/	A.06-12-009, A.06-12-010	San Diego Gas & Electric Co., and Southern California Gas Co.
2007	Kentucky 36/	2007-00143	Kentucky-American Water Co.
2007	Kentucky 36/	2007-00089	Delta Natural Gas Co.
2007	Maine 71/	2007-00215	Central Maine Power
2008	Kansas 40/	08-ATMG-280-RTS	Atmos Energy Corporation
2008	New Jersey 1/	GR07110889	New Jersey Natural Gas Co.

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2008	North Dakota 37/	PU-07-776	Northern States Power/Xcel Energy
2008	Pennsylvania 3/	A-2008-2034045 et al	UGI Utilities, Inc. / PPL Gas Utilities Corp.
2008	Washington 63/	UE-072300, UG-072301	Puget Sound Energy
2008	Pennsylvania 3/	R-2008-2032689	Pennsylvania-American Water Co. - Coatesville
2008	New Jersey 1/	WR08010020	NJ American Water Co.
2008	Washington 63/ 64/	UE-080416, UG-080417	Avista Corporation
2008	Texas 65/	473-08-3681, 35717	Oncor Electric Delivery Co.
2008	Tennessee 66/	08-00039	Tennessee-American Water Co.
2008	Kansas	08-WSEE-1041-RTS	Westar Energy, Inc.
2009	Kentucky 36/	2008-00409	East Kentucky Power Coop.
2009	Indiana 29/	43501	Duke Energy Indiana
2009	Indiana 29/	43526	Northern Indiana Public Service Co.
2009	Michigan 33/	U-15611	Consumers Energy Company
2009	Kentucky 36/	2009-00141	Columbia Gas of Kentucky
2009	New Jersey 1/	GR00903015	Elizabethtown Gas Company
2009	District of Columbia 7/	FC 1076	Potomac Electric Power
2009	New Jersey 1/	GR09050422	Public Service Gas & Electric Co.
2009	Kentucky 36/	2009-00202	Duke Energy Kentucky Co.
2010	Kentucky 36/	2009-00549	Louisville Gas and Electric Co.
2010	Kentucky 36/	2009-00548	Kentucky Utilities Co.
2010	New Jersey 1/	GR10010035	Southern New Jersey Gas Co.
2010	Hawaii 42/	2009-0286	Maui Electric Co.
2010	Hawaii 42/	2009-0321	Hawaii Electric Light Co.
2010	Hawaii 42/	2010-0053	Hawaiian Electric Co.
2010	Lancaster 3/	R-2010-2179103	Lancaster Water Fund
2011	Kansas 40/	11-KCPE-581-PRE	Kansas City Power and Light Co.
2011	Delaware 24/	11-207	Artesian
2012	Kentucky 36/	2012-00221	Kentucky Utilities Company
2012	Kentucky 36/	2012-00222	Louisville Gas and Electric Company
2012	Massachusetts 67/	DPU 12-25	Bay State Gas Company
2012	District of Columbia 7/	FC 1093	Washington Gas Light Company
2012	New Jersey 1/	WR11070460	New Jersey American Water
2012	New Jersey 1/	ER11080469	Atlantic City Electric Company
2013	Michigan 33/	U-16769	Michigan Consolidated Gas
2013	New Jersey 1/	ER12111052	Jersey Central Power & Light
2013	Alberta 68/	2322	ATCO Pipelines
2013	North Dakota 37/	PU-12-813	Northern States Power

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2013	Massachusetts 67/	D.P.U 13-07	New England Gas Company
2013	Wyoming 69/	20000-427-EA-13	Rocky Mountain Power
2013	New York 70/	13-E-0030	Consolidated Edison
2013	Maine 71/	2013-00168	Central Maine Power
2014	Alberta 68/	2739	Enmax Power Company
2014	West Virginia 2/	14-0701-E-D	Monongahela Power Company
2014	West Virginia 2/	14-1151-E-D	APCO
2015	Maryland 8/	9319	Potomac Edison
2015	Maryland 8/	9385	PEPCO
2015	West Virginia 2/	15-0674-WS-D	WV American Water Company
2016	Pennsylvania 3/	R2016-2529660	Columbia Gas of Pa.
2017	Hawaii 42/	2016-0431	Hawaiian Electric

PARTICIPATION AS NEGOTIATOR IN FCC TELEPHONE DEPRECIATION RATE REPRESCRIPTION CONFERENCES

COMPANY	YEARS	CLIENT
Diamond State Telephone Co. 24/	1985 + 1988	Delaware Public Service Comm
Bell Telephone of Pennsylvania 3/	1986 + 1989	PA Consumer Advocate
Chesapeake & Potomac Telephone Co. - Md. 8/	1986	Maryland People's Counsel
Southwestern Bell Telephone – Kansas 20/	1986	Kansas Corp. Commission
Southern Bell – Florida 4/	1986	Florida Consumer Advocate
Chesapeake & Potomac Telephone Co.-W.Va. 2/	1987 + 1990	West VA Consumer Advocate
New Jersey Bell Telephone Co. 1/	1985 + 1988	New Jersey Rate Counsel
Southern Bell - South Carolina 22/	1986 + 1989 + 1992	S. Carolina Consumer Advocate
GTE-North – Pennsylvania 3/	1989	PA Consumer Advocate

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PARTICIPATION IN PROCEEDINGS WHICH WERE SETTLED BEFORE TESTIMONY WAS SUBMITTED

STATE	DOCKET NO.	UTILITY
Maryland 8/	7878	Potomac Edison
Nevada 21/	88-728	Southwest Gas
New Jersey 1/	WR90090950J	New Jersey American Water
New Jersey 1/	WR900050497J	Elizabethtown Water
New Jersey 1/	WR91091483	Garden State Water
West Virginia 2/	91-1037-E	Appalachian Power Co.
Nevada 21/	92-7002	Central Telephone - Nevada
Pennsylvania 3/	R-00932873	Blue Mountain Water
West Virginia 2/	93-1165-E-D	Potomac Edison
West Virginia 2/	94-0013-E-D	Monongahela Power
New Jersey 1/	WR94030059	New Jersey American Water
New Jersey 1/	WR95080346	Elizabethtown Water
New Jersey 1/	WR95050219	Toms River Water Co.
Maryland 8/	8796	Potomac Electric Power Co.
South Carolina 22/	1999-077-E	Carolina Power & Light Co.
South Carolina 22/	1999-072-E	Carolina Power & Light Co.
Kentucky 36/	2001-104 & 141	Kentucky Utilities, Louisville Gas and Electric
Kentucky 36/	2002-485	Jackson Purchase Energy Corporation
Kentucky 36/	2009-00202	Duke Energy Kentucky
New Jersey 1/	ER09080664	Atlantic City Electric Co.
New Jersey 1/	ER09080668	Rockland Electric Co.

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Clients

1/ New Jersey Rate Counsel/Advocate	36/ Kentucky Attorney General
2/ West Virginia Consumer Advocate	37/ North Dakota Public Service Commission
3/ Pennsylvania OCA	38/ Kansas Industrial Group
4/ Florida Office of Public Advocate	39/ City of Witchita
5/ Toms River Fire Commissioner's	40/ Kansas Citizens' Utility Rate Board
6/ Iowa Office of Consumer Advocate	41/ NIPSCO Industrial Group
7/ D.C. People's Counsel	42/ Hawaii Division of Consumer Advocacy
8/ Maryland's People's Counsel	43/ Nevada Bureau of Consumer Protection
9/ Idaho Public Service Commission	44/ GCI
10/ Western Burglar and Fire Alarm	45/ Wisc. Citizens' Utility Rate Board
11/ U.S. Dept. of Defense	46/ Vermont Department of Public Service
12/ N.M. State Corporation Comm.	47/ Oklahoma Corporation Commission
13/ City of Philadelphia	48/ National Assn. of State Utility Consumer Advocates
14/ Resorts International	49/ Nova Scotia Utility and Review Board
15/ Woodlake Condominium Association	50/ Florida Office of Public Counsel
16/ Illinois Attorney General	51/ Maryland Public Service Commission
17/ Mass Coalition of Municipalities	52/ MCI
18/ U.S. Department of Energy	53/ Transmission Agency of Northern California
19/ Arizona Electric Power Corp.	54/ Florida Industrial Power Users Group
20/ Kansas Corporation Commission	55/ Sierra Club
21/ Public Service Comm. – Nevada	56/ Our Children's Earth Foundation
22/ SC Dept. of Consumer Affairs	57/ National Parks Conservation Association, Inc.
23/ Georgia Public Service Comm.	58/ Missouri Office of the Public Counsel
24/ Delaware Public Service Comm.	59/ The Utility Reform Network
25/ Conn. Ofc. Of Consumer Counsel	60/ Colorado Office of Consumer Counsel
26/ Arizona Corp. Commission	61/ MD State Senator Paul G. Pinsky
27/ AT&T	62/ MD Speaker of the House Michael Busch
28/ AT&T/MCI	63/ Washington Office of Public Counsel
29/ IN Office of Utility Consumer Counselor	64/ Industrial Customers of Northwestern Utilities
30/ Unitel (AT&T – Canada)	65/ Steering Committee of Cities
31/ Public Interest Advocacy Centre	66/ City of Chattanooga
32/ U.S. General Services Administration	67/ Massachusetts Attorney General
33/ Michigan Attorney General	68/ Alberta Office of the Utilities Consumer Advocate
34/ New Mexico Attorney General	69/ Wyoming Industrial Energy Consumers
35/ Environmental Protection Agency Enforcement Staff	70/ New York State Department
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Debate on the Use of Customer Discount Rates

THE USE OF CUSTOMER DISCOUNT RATE
IN REVENUE REQUIREMENT COMPARISONS

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By

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Good Morning. It is a pleasure and an honor to appear before you today and engage in this debate. I would like to thank Dr. Cowles and Dr. White for the invitation. I am a consultant specializing in public utility rate matters. I have presented testimony in a number of proceedings, generally on behalf of public utility customers and regulatory commission staffs.

Typically my testimony has presented alternative recommendations to a utility's revenue requirement filing. I have found that most issues in a public utility rate case revolve around conceptual "gray areas" amenable to debate. In fact, Dr. White and I have met in the past on the battlefield to discuss certain issues, and today, Dr. Howe and I debate another of the gray areas.

ISSUES

The issue I intend to explore today is the validity of the use of customer discount rates to evaluate revenue requirement comparison models. I will also consider the relationship between utility and customer discount rates. Finally, I will discuss some of the measurement problems in determining the level of the customers discount rate.

I conclude that the customers' discount rate is a relevant statistic in evaluating ratemaking models and that that rate will always be higher than the rate of the utility studied.

DISCOUNT RATE

A discount rate is a compound interest factor used to determine the net present value of a stream of future cash flows. It embodies the user's time preference, inflation, and risk expectations.

When a firm evaluated new investments, it must assume that they are as risky as current investments; hence, the appropriate discount rate is the firm's current cost of capital. Public utilities may use their last allowed overall rate of return, that is, the embedded cost of capital, or their perception of incremental capital costs taking into consideration anticipated trends in debt and equity cost rates.

There are broadly two classes of public utility customers - individuals and firms. The discount rate of a firm is hypothetically derived in the same manner as a utility's cost of capital, that is, through an analysis of the composite effect of business and financial risk. Large heavily capitalized utility customers will likely have composite risk characteristics not much different from utilities. Smaller firms, however, particularly those with limited capitalization will in all probability have a cost of capital, and hence discount rates, higher than the utility that serves them. The individual's discount rate is quite another matter.

In his text Financial Markets and Institutions (McMillan Publishing Co., Inc. 1983) Robert D. Auerbach states:

> The interest rate individuals use to discount future expected income streams to obtain present values is not observed in the market place. It is the subjective real interest rate in each individual's mind that is fundamental to his or her valuation of securities." (p.147).

The problem with individual consumers' discount rates is that it is a spectrum, not a single number. Consider the extremes. At the low end of the income spectrum are consumers living at or below the poverty level. For such individuals the discount rate is practically infinity because the deferral of a dollar on income means that the consumer must forego basic necessities of life; food, clothing, shelter.

As income increase, the opportunity cost of the incremental dollar falls. For low to moderate income consumers, who are likely to be net debtors, it is the finance charge rate on consumer credit -- 18 to 24 percent. At the high income end of the spectrum, the discount rate becomes the marginal return from individual investments - stocks, bonds, real estate, tax shelters. One this is certain, the individual discount rate is not the discount rate of the utility. For the vast majority of individuals it will be substantially higher.

Hence, while it is possible to determine the current embedded cost of capital of utilities and large corporate customers through observation of published data, it is much more difficult - arguably impossible - to determine a composite individual and small firm discount rate. Nevertheless, individuals are highly sensitive to the impact of changes in their future cash flows, as evidenced by today's current wave of mortgage refinancings. The individual's discount rate, although subjective, is a very real factor in his or her economic behavior.

REVENUE REQUIREMENT COMPARISON MODELS

Revenue requirement comparison models are typically presented as evidence in utility rate proceedings to persuade regulators to adopt one or another of ratemaking alternatives having different streams of future costs and benefits.

A revenue requirement model presents an implied choice between the several alternatives that are often highly sensitive to the discount rate.

I have two examples of ratemaking models with me today. Both compare revenue requirement streams that differ as to their future timing. The one characteristic common to both of the models is that each presumes a constant rate of return throughout the period, and that rate of return is the utility's cost of capital. The equity component of the rate of return considers inflation, risks and the utility's investors expectations.

Model 1 was prepared by me for presentation in a Public Utilities Fortnightly Article. It had its genesis in testimony I presented regarding the subject matter in a proceeding a number of years prior to the PUF article.

This model deals with the once controversial subject of tax normalization versus flow through. It is a five-year revenue requirement comparison of the two methods. It assumes a constant 46 percent tax rate, an 11.75 percent pretax and 9.887 percent post-tax cost of capital. The model reveals that if the hypothetical utility's post-tax cost of capital is used to discount the two cash flow streams they are equal, that is, the net present values of both streams are the same --$115,244.

The second example is a model prepared by Dr. White which considers the economic implications of a depreciation reserve deficiency. As we all know, service life estimates are rarely fixed and many time are changed throughout the life of utility plant. When this occurs the issues of remaining life depreciation and reserve imbalances generally arise. Dr. White's model compares a straight-line whole life revenue requirement stream assuming that original life estimates were correct, with an alternative stream in which the original service life estimates were changed and the remaining life technique was used to correct the resulting reserve imbalance. Dr. White used the utility's after-tax cost of capital as a discount factor to demonstrate the equality of the two revenue requirement streams.

Dr. White and I both determined that it was proper to discount the cash flow streams, and we both demonstrated that the utility's discount factor is defined as its after-tax rate of return. Furthermore, in both examples we have imputed that discount rate to the utility's customers. Thus, using that assumption, all other things being equal, it was presumed that the parties to whom the alternatives were presented would use the utility's discount factor to make the implied choice because any other discount would skew the results and eliminate the equality.

It is reasonable to assume that the customers would use the utility's cost of capital to evaluate cash flow streams under those circumstances? I think the answer is no. The customer would use their own discount rates to evaluate the alternatives.

IMPACT OF THE CUSTOMERS DISCOUNT RATE

The impact of using the customers discount rate is the reason for our debate. In the example 1, normalization vs. flow through model, any rate higher than the utility's after tax cost of capital would support the conclusion, all other thing being equal, that flow through was the superior method. In fact, all things were not equal in that debate and normalization was adopted. However, it is important to understand that a recognition of the customers discount rate if indeed higher than the utility's would largely explain why there was so much—about 20 years worth of customer opposition to normalization.

MEASUREMENT

If it could be shown that the customer's discount rate was always equal to a utility's embedded after tax cost of capital then we would not be having this debate because the customers rate would always implicitly recognized in revenue requirement model. On the other hand, if the customer rate is not equal to the utility's cost rate, we are faced with a measurement problem. As I stated previously, there are broadly two classes of utility customers: firms and individuals. Large firm's discount rates can be observed in the market place. Small firm and individual discount rates, however, are not observed in the market place. They are fundamentally subjective personal valuation standards.

I am not here today to advocate any particular measurement technique, nor am I here to estimate a composite customer discount rate. However, I will state that the individuals discount rate is different from and higher that the utility's cost of capital.

Obviously, there is a wide range of customer discount rate measurement possibilities. In the past, I have seen estimates tied to consumer credit card costs. I have also seem estimates of composite (individuals and firms) customer discount rates in which a rate is estimated for both classes of customers and then weighted to determine both classes of customers and then weighted to determine the composite. I have also seen reference to the social rate of discount which is based on the opportunity cost of public spending. All of these measurement approaches to determine the customer's discount rate have one consistent characteristic. The yield result that bear no relationship to the utility's cost of capital.

CONCLUSION

The issue today is whether the customer's discount rate should be considered in a revenue requirement comparison. I submit that the customers discount rate should be considered when a model is presented which implies that choice can be made. In that circumstance, it is the discount rate of the parties to whom the choice is presented that is the relevant statistic.

I thank you for listening and once again would like to thank Dr. White and Dr. Cowles for inviting me here today.

COMPARISON OF NORMALIZATION AND FLOW-THROUGH REVENUE REQUIREMENTS REFLECTING RATE BASE REDUCTION OF ACCUMULATED DEFERRED TAXES

	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Normalization Cost of Service	$38,309	$34,226	$29,048	$23,995	$21,977	$147,515
Net Present Charges	34,862	28,344	21,892	16,429	13,716	115,243*
Flow-through Cost of Service	34,050	19,314	16,504	44,361	40,699	154.928
Net Present Charges	30,986	15,995	12,438	30,424	25,401	115,244*

Cost of Capital - Post-tax = .09887

	Per Cent	Cost	Pretax Weighted Cost	Tax Effect	Posttax Weighted Cost
Debt	45	.09	.0405	(.01863)	.02187
Equity	55	.14	.0770	-0-	.07700
Total	100		.1175	(.01863)	.09887

*** Difference in totals due to rounding.**

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COMPARISON OF REVENUE REQUIREMENTS

	Correct Service Life Estimate (No Reserve Deficiency)			Revised Service Life Estimate (Reserve Deficiency)		
	Cash Flow		Revenue	Cash Flow		Revenue
Year	Debt	Equity	Requirements	Debt	Equity	Requirements
1	$101.40	$87.60	$408.00	$78.90	$72.60	$333.00
2	67.14	63.78	460.57	39.27	45.95	366.47
3	60.47	59.38	566.48	84.53	77.18	643.83
4	56.94	57.30	781.55	78.88	73.10	852.78
5	663.89	462.35	1,425.61	683.70	476.16	1,490.73
Present Value	$600.00	$400.00	$2,563.83	$600.00	$400.00	$2,563.83

	Per Cent	Cost	Pretax Weighted Cost	Tax Effect 1/	Pretax Weighted Cost
Debt	60	.12	.72	(.036)	.36
Equity	40	.17	.68	-0-	.68
Total	100		1.40		.104

1/ 50 percent tax rate

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Exhibit (MJM-2)

Credit card rates are now at their highest level in history and may weigh on the economy

Published Thu, May 16 2019 3:52 PM EDTUpdated Thu, May 16 2019 4:18 PM EDT
Kate Rooney@KrOOney

Key Points

- Americans now pay their banks an average 17% interest on credit cards — the highest level recorded by the Fed.
- The rising monthly cost for U.S. consumers may be one reason they're spending less, as April's weak retail sales laid out. The combination doesn't bode well for GDP growth.
- "This is key because of the obvious influence that consumers have on the overall economy," said Peter Boockvar, Chief Investment Officer of Bleakley Advisory Group. "The trajectory is creeping up and is something that we have to watch closely."

Exhibit___(MJM-2)

Man holding a credit card and a wallet.
mp_develops | Twenty20

It costs more than ever to pay with a credit card. Consumers may be spending less as a result, which could be a drag on economic growth.

Americans now pay their banks an average 16.9% interest on credit cards — the highest level ever, according to the Federal Reserve. The skyrocketing borrowing rate does not bode well for the economic health of consumers, and therefore U.S. growth.

"This is key because of the obvious influence that consumers have on on the overall economy," said Peter Boockvar, chief investment officer of Bleakley Advisory Group. "The trajectory is is creeping up and is something that we have to watch closely."

With global trade slowing and worries about exports, Boockvar said the U.S. consumer has been a bright spot. Unemployment is at a 50-year lows and wages are rising. But softer-than-expected consumer spending data this week called some of that strength into question. U.S. retail sales fell 0.2% in April, the Commerce Department said Wednesday. Retail sales make up about one-third of consumer spending, which drives most economic activity.

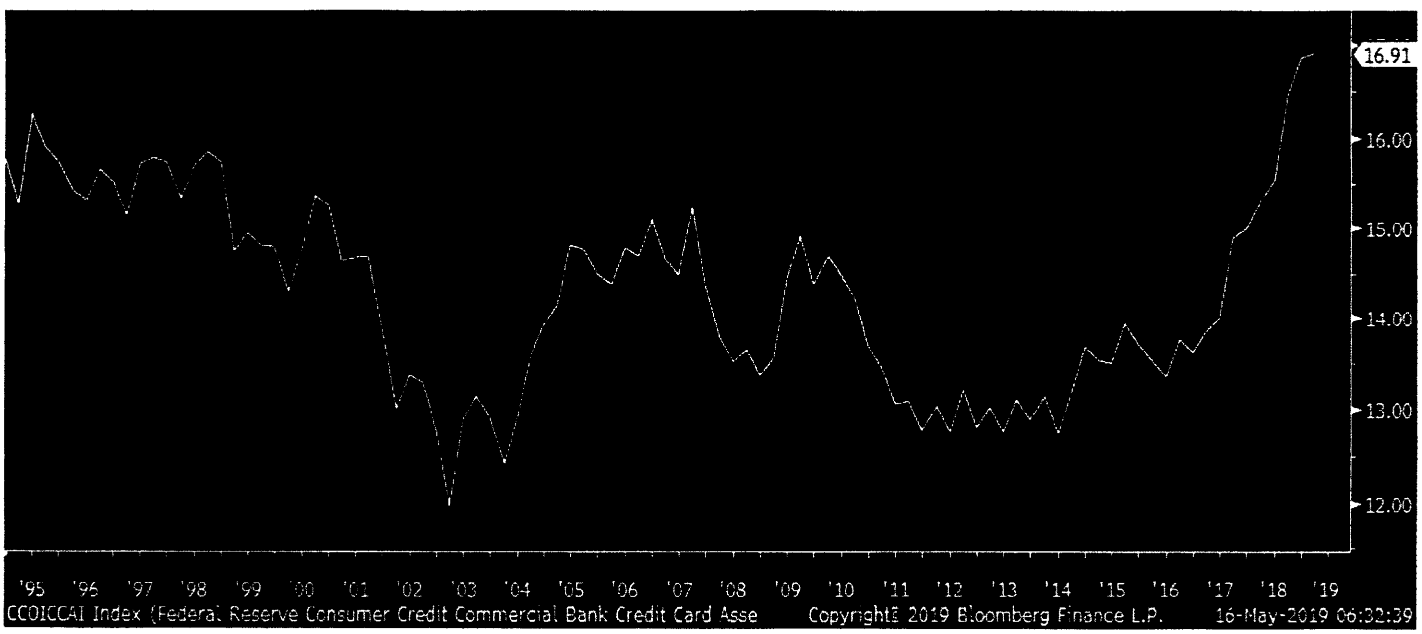
Softness in consumer spending briefly spooked stock markets this week, which were already seesawing thanks to trade-war uncertainty. While it's hard to quantify to what extent, Boockvar said that retail weakness could have been partially due to the high cost of credit.

"This is one of the factors that is keeping things in check," Boockvar said. "Maybe these very high interest costs are overwhelming people's ability to pay back. It also coincides with a decline in say the savings rate and rising gasoline prices and is something we ought to pay attention to."

The Federal Reserve's recent rake hikes have caused an increase in borrowing rates across the board, with credit card rates well above other forms of debt. For instance, the average 60-month auto loan rate is around 5.2% and the personal loan rate is about 10.4%, according to the Fed.

The Fed's short-term lending rate is now targeted between 2.25% and 2.5%. However, it has gone up nine times since December 2015 and has triggered increases across the board in consumer debt instruments, due in part because it costs banks more to borrow.

Average credit card interest rates since 1994



Boockvar said the main reason for the higher-than-average spike in card rates is because of post-financial crisis regulation. In 2009, Congress passed the Credit Card Accountability, Responsibility, and Disclosure Act. Among other things, it limited the flexibility banks would have to raise interest rates on credit card holders.

Exhibit___(MJM-2)

"The unintended consequence, which there always is when restrictions are placed on the free market, was that banks then started off the credit card rate at a higher level than otherwise," Boockvar said in a note to clients this week.

Paying for 'free' rewards

Another reason for higher borrowing costs from banks is a need to pay for those flashy rewards. Banks are luring in customers with travel and spending offers, or the occasional a cash bonus to sign up. They need to be paid for, somehow.

"Who do you think pays for all the rewards we receive by utilizing our charge cards? Banks recoup the costs via higher card rates," Boockvar said.

After a lull in the financial crisis, credit card issuance has mostly rebounded. According to Federal Reserve data, more than 60 percent of the population has at least one credit card account.

Another potential warning sign to watch is credit card delinquencies. In the first quarter, the amount of people unable to make a credit card payment hit the highest level in seven years, according to a report by the New York Fed this week, using Equifax data. People between the ages of 18 and 29, so-called millennials, drove the spike in overdue payments.

"Credit card delinquency rates have been trending upward in the past few years—likely reflecting, in part, the increased presence of younger borrowers in the credit card market," Andrew Haughwout, senior vice president in the microeconomic research group of Federal Reserve Bank of New York, said in a blog post this week.

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Michael J. Majoros, Jr., being first duly sworn on oath, deposes and states that he has read the testimony and any exhibits submitted in the above captioned matters under his name, that they were prepared by him or under his direction, that he knows the contents thereof, and that the same are true and correct to the best of his knowledge and belief.

Michael J. Majoros, Jr.

Subscribed and sworn to before me this 08 day of May, 2019.

Notary Public
My Commission Expires: 5/14/23

ASHLEY NICOLE HANNINEN
Notary Public - Maryland
City of Baltimore
My Commission Expires on
May 14, 2023