through the system for each class of customers, whenever those occur, whether or not those demands coincide with the system peak.[759]

582. The Department's witness, Mr. Zajicek, identified a number of problems with the proposed Average and Excess method. First, he observed that the cost of each customer class' annual use of the system is already reflected in the CCOSS. Specifically, energy costs, including the costs of natural gas and operation and maintenance expense are appropriately allocated to each customer class based on the annual amount of natural gas that each class uses (the energy allocator). A concern with the proposed Average and Excess method is that if, in addition, costs of the demand portion of the distribution system are allocated to customer classes based in part on the annual amount of natural gas used by each customer class, too little of the demand costs would be allocated to a customer class that demands a large amount of energy at the system peak but uses relatively less natural gas over the course of the year.[760]

583. Similarly, according to Mr. Zajicek, this approach may allocate too much of the costs of the size of the distribution system to a customer class that uses relatively equal amounts of natural gas throughout the year, especially if such a class is curtailed from taking service as an interruptible customer during the system peak.[761]

584. For these reasons, the Department disagreed with the proposal to use the Average and Excess allocation method in MERC's next rate case unless it can be shown reasonably to reflect how costs of the distribution system are incurred.[762]

585. MERC also disagreed with the OAG's recommendation to file a CCOSS using the Average and Excess approach in future rate cases. MERC asserted that the Minimum System CCOSS is the appropriate model to use given the nature of MERC's system. MERC also stated that it already provides a proxy that is akin to the Average and Excess method; so a requirement to file an Average and Excess model would be a duplication of what is already being provided by MERC with existing, available data.[763]

586. The Administrative Law Judge concludes that the Department has raised valid questions about whether the Average and Excess method reasonably reflects how costs of the distribution system are incurred. In addition, MERC stated that it provides a proxy that is akin to the Average and Excess method. For these reasons, the Administrative Law Judge recommends that the Commission not adopt the OAG's recommendation that MERC be required to file a CCOSS using the Average and Excess method in its next rate case.

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[759] Ex. 410 at 7 (Zajicek Rebuttal).
[760] Ex. 410 at 8 (Zajicek Rebuttal).
[761] Ex. 410 at 8 (Zajicek Rebuttal).
[762] Ex. 410 at 8-9 (Zajicek Rebuttal).
[763] Ex. 35 at 31 (Hoffman Malueg Rebuttal).

587. Similarly, the Administrative Law Judge does not recommend the Commission require MERC to file a Basic System CCOSS in its next rate case because of the limitations of that model with regard to cost causation of the distribution system.

588. Instead, the Administrative Law Judge recommends that MERC be required to file a zero-intercept CCOSS and a minimum-size CCOSS in its next rate case, as well as any other CCOSS(s) ordered by the Commission at the completion of any generic proceeding undertaken by the Commission.

6. Former IPL Customer Considerations in the CCOSS

589. MERC did not conduct a separate cost of service study for serving the customers who were formerly served by IPL and are now served by MERC.[764] As noted above, on May 1, 2015, MERC acquired IPL's assets and the former IPL customers are now being served by MERC.[765]

590. The OAG maintained that MERC improperly assumed that the customers in the former IPL area have the same costs as other MERC customers. According to OAG witness, Mr. Nelson, the former IPL service area "likely has different customer density, age of system, [and] load profiles, among other characteristics."[766]

591. For this reason, the OAG recommended that no weight be given to MERC's CCOSS with respect to the costs caused by the former IPL customers. Instead, the rates for the former IPL area should be decided on policy considerations, without considering the cost of service.[767]

592. MERC disagreed with the OAG's position. MERC witness, Ms. Hoffman Malueg, explained that MERC's CCOSS accounted for the load profiles of the former IPL customers within its CCOSS.[768] Ms. Hoffman Malueg also disagreed with the OAG's assertion that the former IPL customers have different costs than MERC's other customers because the former IPL customers are relatively homogenous with respect to MERC's NNG rate schedules.[769]

593. The Administrative Law Judge finds that MERC has properly accounted for the former IPL customers in its CCOSS. The Administrative Law Judge is unaware of any instance where the Commission has required a separate CCOSS for a newly acquired area.[770] Furthermore, the OAG does not dispute that MERC's former IPL customers are currently paying well below their cost of service.[771]

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[764] Ex. 304 at 27 (Nelson Direct).
[765] Ex. 39 at 19 (Lee Rebuttal).
[766] Ex. 304 at 27 (Nelson Direct).
[767] Ex. 304 at 27-28 (Nelson Direct).
[768] Ex. 35 at 52, Schedule JCHM-R3 (Hoffman Malueg Rebuttal).
[769] Ex. 35 at 52-54, Schedule JCHM-R3 (Hoffman Malueg Rebuttal).
[770] *See* Ex. 304 at 27-28 (Nelson Direct).
[771] *See* Ex. 304 at 38 (Nelson Direct); OAG Initial Br. at 47 (June 29, 2016) (eDocket No. 20166-122790-01).

594. The Administrative Law Judge further concludes that it is reasonable to consider MERC's zero-intercept CCOSS results as one factor in setting rates for all of MERC's customers, including MERC's customers in the former IPL service area.

7. Other Recommendations

595. As noted above, in MERC's last rate case, the Commission required MERC in this case to:

- collect data on additional variables;
- avoid aggregating data;
- check ordinary least squares regression assumptions and correct for any violations; and
- improve the transparency of its zero intercept analysis.[772]

596. The Department reviewed the information provided by MERC to address these requirements.[773]

597. With regard to data aggregation, the Department noted that MERC "attempted to avoid aggregation of data" to the extent possible. The Department, however, recommended that MERC gather and use project-level data for its zero-intercept study in its next rate case.[774]

598. MERC disagreed with the Department's recommendation on project-level data. MERC stated that it is not able to gather a sufficient amount of project-level data for adequate use within a Minimum System study.[775] In addition, MERC does not read the Commission's decision in the last rate case to require the use of project-level data.[776]

599. During the evidentiary hearing, MERC and the Department reached an agreement regarding the collection and future use of project-level data. Specifically, MERC and the Department agreed that MERC would: (1) collect project-specific data on installation footage, pipe diameter, and cost; (2) research, and as soon as possible, begin collection of distribution asset retirement at this same project-level detail; and (3) explore the use of this project-specific data in its zero-intercept CCOSS in future rate case filings.[777]

600. The Department also recommended that the Commission require MERC to provide a substantive explanation and justification of its classification and allocation

[772] 2013 MERC RATE CASE ORDER at 47.
[773] Ex. 409 at 9-13 (Zajicek Direct); Ex. 410 at 13 (Zajicek Rebuttal); Ex. 411 at 1-5 (Sur-Surrebuttal).
[774] Ex. 409 at 10 (Zajicek Direct); Ex. 410 at 17 (Zajicek Rebuttal).
[775] Ex. 36 at 12 (Hoffman Malueg Surrebuttal).
[776] Ex. 36 at 14 (Hoffman Malueg Surrebuttal).
[777] Tr. Vol. 2 at 34-35 (Zajicek); Ex. 411 at 8 (Zajicek Sur-Surrebuttal).

methods when it files its CCOSS in the next rate case.[778] MERC did not object to this recommendation.

601. The Administrative Law Judge finds the agreement reached between MERC and the Department with respect to project-level data is reasonable and recommends it be accepted by the Commission. The Administrative Law Judge also recommends that MERC be required to provide a substantive explanation and justification of its classification and allocation methods when it files its CCOSS in the next rate case.

C. Revenue Apportionment – Disputed Item

602. Once the CCOSS analysis is complete, the Commission evaluates how to apportion the approved revenue requirement among the various customer classes that receive service from the Company. The division of responsibility for producing the required revenues among the customer classes is called revenue apportionment.

603. Revenue apportionment is important because it ultimately determines the price customers are charged for their gas services.

604. There is no requirement that rates for all classes be equal, but any rate differences must be reasonable.[779] In addition, as discussed above in paragraph 516, the Commission has historically considered a range of cost and non-cost factors in setting rates.

605. In developing its proposed revenue apportionment, MERC considered the following goals:

- collect total revenues sufficient to allow MERC to recover its cost of operations for the test year, including a reasonable return on investment;
- reflect the cost of providing service to each customer class, as supported by MERC's CCOSS, while giving consideration to non-cost factors, e.g., value of service, where appropriate;
- provide overall revenue stability to MERC;
- encourage sound economic energy use;
- minimize cross-subsidization between rate classes;
- avoid large bill impacts or "rate shock";
- minimize bypass threats to large industrial customers;

[778] Ex. 411 at 8 (Zajicek Sur-Surrebuttal).
[779] *See* Minn. Stat. § 216B.03 (2016).

- limit the impact of the proposed rates on low-income customers; and
- provide flexibility in pricing and service conditions, which will allow MERC's natural gas services to be competitive with other energy sources.[780]

606. MERC's zero-intercept CCOSS results were its starting point for the apportionment of the retail revenue requirement among the rate classes. Other rate design goals were then considered, as noted above, such as maintaining competitive pricing, and limiting large bill impacts or "rate shock." MERC's goal was to recover as closely as possible the costs imposed by each class, while avoiding unacceptably high billing impacts.[781]

607. MERC's proposed revenue apportionment was presented in a schedule that compared test year operating revenue under present and proposed rates by customer class of service, showing the difference in revenue and percentage change.[782] A detailed comparison of test year operating revenue under present and proposed rates by type of charge, including minimum demand, energy by block, gross receipts, automatic adjustments, and other charge categories within each rate schedule and within each customer class of service, as well as a side-by-side comparison of the amount of revenue generated by each rate component under the current and proposed monthly fixed charges, demand charges, and per therm rates for each rate class, were also presented in a schedule.[783]

608. The Department suggested that the revenue apportionment approved for MERC should balance the goal of moving classes closer to cost with the goal of avoiding rate shock and reducing inter-class subsidies.[784] The Department initially proposed its own revenue apportionment, but later withdrew it.[785] Instead, the Department recommended that MERC's final recommended revenue apportionment be adopted, as reflected in Tables 1 and 2 and Schedule SLP-S-1 of the Surrebuttal Testimony of Susan Peirce.[786] If the Commission adopts a different revenue requirement, the Department recommended that revenues be apportioned among the classes based on the apportionment of total revenue percentages excluding gas costs reflected in SLP-S-1.[787]

609. The OAG recommended a revenue apportionment that differed slightly from what MERC recommended, on a percentage basis.[788] The OAG's revenue

[780] Ex. 37 at 6 (Lee Direct).
[781] Ex. 37 at 8 (Lee Direct).
[782] Ex. 37 at 10, ASL-1 at Schedule 3, Summary (including gas costs), and Schedule 5, Summary (not including gas costs) (Lee Direct).
[783] Ex. 37 at 10-11, ASL-1 at Schedule 3 (including gas costs), Schedule 5 (not including gas costs), and Schedule 7 (Lee Direct).
[784] Ex. 405 at 15 (Peirce Direct).
[785] Ex. 405 at 15-18 (Peirce Direct); Ex. 406 at 2-4 (Peirce Surrebuttal).
[786] Ex. 406 at 2-4 (Peirce Surrebuttal).
[787] Ex. 406 at 4 (Peirce Surrebuttal).
[788] Ex, 304 at 36, Table 4 (Nelson Direct)

apportionment sought to ease the transition for former IPL gas customers in southern Minnesota who recently became MERC customers.[789]

610. As noted above, on December 8, 2014, the Commission approved the sale of IPL's Minnesota natural gas distribution system and assets, and the transfer of its Minnesota service rights and obligations to MERC. The transfer, which occurred on May 1, 2015, affected approximately 10,600 customers in twelve communities in southeastern and south-central Minnesota including Adams, Albert Lea, Clarks Grove, Congor, Geneva, Glenville, Hollandale, Le Roy, Rose Creek, Taopi, and Wykoff. [790]

611. IPL's customers had not had a rate increase since 1996.[791]

612. To ease the rate transition for the former IPL customers, the Commission ordered that: "IPL customers affected by the transaction be transitioned to MERC's tariffs [at the time the sale closes], except that MERC maintain … customer charges and purchase gas adjustments consistent with IPL's tariffs." The Commission further provided that "[t]his arrangement will continue until MERC's next rate case, at which time MERC will reconcile the two fuel supply systems into one."[792]

613. With this guidance in mind, the OAG's witness, Mr. Nelson, stated that he first considered the OAG's Basic System CCOSS and MERC's proposed CCOSS in developing his proposed revenue apportionment.[793] Mr. Nelson then adjusted his revenue apportionment recommendation based on a three step process to fully transition the former IPL customers onto MERC's tariffs. This process included a phase-in of customer charge increases over three rate cases. The OAG proposed that the revenue shortfall of each former IPL customer class be absorbed by both of the respective NNG and Consolidated customer classes. The OAG further suggested that the split be based off of revenues.[794]

614. The OAG's witness, Mr. Nelson, noted that in developing his proposed revenue apportionment, he attempted to collect less revenue from classes that were paying above their cost of service, and increase the revenue collected from the classes that were paying below their cost of service. He used both the OAG's and MERC's CCOSSs to determine the level of revenue for each class. He then made the adjustments discussed above to the customer charges from the former IPL customers, which lowered the revenue collected from the former IPL customers.[795]

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789 Ex. 304 at 33 (Nelson Direct),
790 Ex. 39 at 19 (Lee Rebuttal); *In the Matter of a Request for the Approval of the Asset Purchase and Sale Agreement Between Interstate Power and Light Co. and Minnesota Energy Resources Corporation*, MPUC Docket No. G-001, G-011/PA-14-107, ORDER APPROVING SALE SUBJECT TO CONDITIONS at 1-2 (Dec. 8, 2014).
791 *Id.* at 2.
792 *Id.* at 3.
793 Ex. 304 at 33 (Nelson Direct).
794 Ex. 304 at 33-35 (Nelson Direct).
795 Ex. 304 at 37 (Nelson Direct).

615. In Rebuttal Testimony, MERC disagreed with the OAG's proposed revenue apportionment for three reasons. First, MERC asserted that the OAG's proposed apportionment was improper because it was based on total revenues, which include the cost of gas. MERC maintained that the cost of gas should be excluded. Second, MERC disagreed with the OAG's CCOSS analysis, and its reliance on the Basic System CCOSS results. Third, MERC disagreed with the OAG's three step transition plan for customer charges, and proposed a two-step transition plan as an alternative for the Commission to consider.[796]

616. In response to MERC's comments, the OAG provided an updated revenue apportionment without the cost of gas in Surrebuttal Testimony.[797]

617. The table set forth below compares MERC's final proposed revenue apportionment to the OAG's final proposed revenue apportionment, without the cost of gas.[798]

[796] Ex. 39 at 4-6, 9, 16-17 (Lee Rebuttal).
[797] Ex. 307 at 23-24 (Nelson Surrebuttal).
[798] Ex. 307 at 24 (Nelson Surrebuttal).

MERC Customer Class	MERC Proposed	OAG Proposed Alternative
RESIDENTIAL SALES		
GS-NNG Residential Sales	51.2%	51.1%
GS-CONSOLIDATED Residential Sales	8.8%	8.7%
GS-ALBERT LEA NNG Residential Sales	2.7%	2.6%
Total	**62.7%**	**62.4%**
SC&I SALES		
GS-NNG SC&I Sales	3.5%	3.3%
GS-CONSOLIDATED SC&I Sales	1.1%	1.0%
GS-ALBERT LEA NNG SC&I Sales	0.2%	0.2%
Total	**4.8%**	**4.5%**
LC&I SALES		
GS-NNG LC&I Sales	15.1%	15.2%
GS-CONSOLIDATED LC&I Sales	4.8%	4.8%
GS-ALBERT LEA NNG LC&I Sales	0.8%	0.8%
Total	**20.6%**	**20.9%**
SMALL VOLUME SALES AND TRANSPORT		
SVI-NNG Sales	2.2%	2.2%
SVI-CONSOLIDATED Sales	0.5%	0.5%
SVI-ALBERT LEA NNG Sales	0.2%	0.2%
SVJ-NNG Sales	0.0%	0.0%
SVJ-CONSOLIDATED Sales	0.0%	0.0%
SVI-NNG Transport	0.2%	0.2%
SVI-CONSOLIDATED Transport	0.2%	0.2%
SVI-ALBERT LEA Transport	0.0%	0.0%
SVJ-NNG Transport	0.3%	0.3%
SVJ-CONSOLIDATED Transport	0.1%	0.1%
Transport for Resale	0.0%	0.0%
Total	**3.8%**	**3.8%**
SUPER LARGE AND LARGE VOLUME SALES AND TRANSPORT		
Total	**8.1%**	**8.5%**

618. The OAG recognized that the proposals are similar but maintained that its revenue apportionment should be adopted. The OAG asserted that its proposal better reflects cost causation because it relies on multiple CCOSS results (Basic System and zero-intercept).[799] In addition, the OAG asserted that proposal would result in smaller customer charge increases for the former IPL customers.[800]

619. The OAG also noted that the former IPL customers will experience a large rate increase under either party's proposal due to three factors: (1) those customers are

[799] OAG Initial Br. at 46-47 (June 29, 2016) (eDocket No. 20166-122790-01); Ex. 304 at 38-40 (Nelson Direct).
[800] Ex. 307 at 25-26 (Nelson Surrebuttal).

being merged onto MERC's NNG PGA; (2) the customer charges for IPL's former customers are lower than MERC's and will go up; and (3) MERC's overall rate increase.[801]

620. While the two revenue apportionment proposals are similar, the Administrative Law Judge concludes that MERC's proposal is the most reasonable for use in this rate case. The Administrative Law Judge reaches this conclusion for two primary reasons.

621. First, MERC's proposal is most consistent with cost causation because it is based on MERC's zero-intercept CCOSS results, whereas the OAG's proposal is based on both the Basic System CCOSS results and the zero-intercept results. As discussed above, the Administrative Law Judge concluded that the Basic System CCOSS results do not properly reflect cost causation on MERC's system.

622. Second, MERC's proposed revenue apportionment is most consistent with the Administrative Law Judge's conclusion about how best to transition former IPL customers to MERC's customer charges. While the Administrative Law Judge agrees that the former IPL customers should not be moved to MERC's existing customer charges in a single rate case because of concerns about rate shock, the Administrative Law Judge concludes that a two-step transition is more reasonable than the three-step transition proposed by the OAG. The reasons for this conclusion are discussed in detail below in the Customer Charge section.

623. Because MERC's proposed revenue apportionment best reflects these underlying decisions and the difference between the two proposals is small, the Administrative Law Judge recommends that the Commission adopt MERC's proposed revenue apportionment. The Administrative Law Judge concludes that MERC's proposed revenue apportionment, which is supported by the Department, appropriately considers both cost and non-cost factors.

D. Customer Charges - Disputed Item

624. The customer charge is a fixed monthly charge assessed without regard to usage levels. It is designed to help recover fixed customer-related costs such as the cost of meters, service lines, meter reading, and billing.[802]

625. MERC seeks to move the customer charges for certain classes closer to the customer cost estimated in its CCOSS.[803]

626. MERC's monthly customer charge is currently $9.50 for Residential service and $18 for General Service- Small Commercial and Industrial (GS-SC&I).[804] In its initial filing, MERC proposed to increase its Residential customer charge to $11 per month for

[801] Ex. 307 at 25 (Nelson Surrebuttal).
[802] 2015 CPE RATE CASE ORDER at 61.
[803] Ex. 37 at 14 (Lee Direct).
[804] Ex. 37 at 19, 46, ASL-1 at Schedule 2 (Lee Direct).

all Residential customers, and to increase its GS-SC&I customer charge to $20 per month for all Small C&I customers.[805]

627. The Department and the OAG disagreed with MERC's proposed customer charges. Both were concerned about the potential bill impacts and rate shock that former IPL customers would experience under MERC's initial proposal.[806]

628. MERC's current monthly charges and the monthly customer charges initially proposed by MERC are set out in the table below.[807]

Customer Class	MERC's CCOSS Customer Cost	Current Customer Charge Existing MERC	Current Customer Charge IPL	Proposed Customer Charge
Residential	$26.27	$9.50	$5.00	$11.00
GS – SC&I	$29.41	$18.00	$5.00	$20.00
GS-LC&I	$46.64	$45.00	$5.00	$45.00
SVI & SVJ-Sales	$110.45	$165.00	$14.00	$170.00
LVI & LVJ-Sales	$116.67	$185.00	$14.00	$190.00
SVI & SVJ - Transport	$254.64	$275.00	$210.00	$280.00
LVI&LVJ - Transport	$260.86	$295.00	$210.00	$300.00
Flex Rate	$383.56	$295.00	-	$300.00
SLVI	$478.55	$460.00	-	$470.00

629. Currently, most of MERC's residential customers pay $9.50 per month for the customer charge. However, residential and small business customers residing in the former IPL service territory, which was acquired by MERC in May 2015, pay only $5.00 per month.[808]

[805] Ex. 37 at 12 (Lee Direct).
[806] Ex. 405 at 19-24 (Peirce Direct); Ex. 304 at 35 (Nelson Direct).
[807] Ex. 405 at 18-19 (Peirce Direct); Ex. 37, ASL-1, Schedule 3 (Lee Direct); Ex. 4, Vol. 3, Doc. No. 12, Schedule 4 (Initial Filing).
[808] Ex. 405 at 18-19 (Peirce Direct); Ex. 37, ASL-1, Schedule 3 (Lee Direct); Ex. 4, Vol. 3, Doc. No. 12, Schedule 4 (Initial Filing).

630. For the former IPL customers, MERC's proposed Residential customer charge represented a 220 percent increase, from $5.00 per month to $11.00 per month.[809]

631. The significant impact of MERC's proposed $11.00 customer charge on former IPL Residential customers is due to MERC's acquisition of IPL's Minnesota gas assets in Albert Lea and the surrounding area. IPL's approximately 10,600 Minnesota natural gas customers have not had a rate increase since 1996. Consequently, the monthly gas customer charge for the former IPL customers has remained $5.00 since 1996.[810]

632. When the Commission approved the sale of IPL to MERC in December of 2014, it ordered MERC to maintain IPL-tariffed customer charges and purchased gas adjustments until MERC's next rate case.[811] However, the Commission noted:

> Minnesota IPL natural gas ratepayers have not experienced a rate increase since 1996 – approximately 18 years. While IPL's Minnesota rates have not gone up in that time, the cost of providing service to IPL's Minnesota customers has likely gone up. As a result, IPL's rates are possibly much lower than the cost of providing service, an untenable situation. IPL could not remain financially viable continuing to charge its customers rates below the cost of providing them service.[812]

633. The large increase in the former IPL customer charges proposed by MERC is also due to the fact that MERC categorizes its customers into different classes than IPL. As a result, some former IPL customers would experience significant customer charge increases simply due to re-categorization into different customer classes.[813]

634. The table below summarizes the former IPL customers newly categorized into MERC's customer classes, and identifies MERC's initial proposed customer charge for those classes.

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[809] Ex. 304 at 34 (Nelson Direct); *see also* Ex. 405 at 18-19 (Peirce Direct).
[810] Ex. 37 at 39-40 (Lee Direct); *In the Matter of a Request for the Approval of the Asset Purchase and Sale Agreement Between Interstate Power and Light Company and Minnesota Energy Resources Corporation*, MPUC Docket No. G001, 011/PA-14-107, ORDER APPROVING SALE SUBJECT TO CONDITIONS at 2 (Dec. 8, 2014).
[811] *Id.* at 3.
[812] *Id.*
[813] Ex. 405 at 19 (Peirce Direct).

IPL Customers Subject to Reclassification of Customer Class[814]

IPL Customer Class	# of IPL customers at time of sale	MERC Customer class	# of customers	IPL customer charge	MERC's Initial Proposed Customer Charge
General Service	10,663	Residential	9,450	$5.00	$11.00
		Small C&I	611	$5.00	$20.00
		Large C&I	602	$5.00	$45.00
Interruptible -sales	45	SVI	39	$14.00	$170.00
		LVI	6	$14.00	$190.00
Interruptible - Transport	4	SVI-Transp.	1	$210.00	$280.00
		LVI-Transp.	3	$210.00	$300.00

635. As reflected in the above table, 611 former IPL General Service customers are classified as Small C&I customers under MERC's classification system, resulting in an increase in their customer charge from $5.00 per month to $20.00 per month under MERC's initial proposal. Similarly, an additional 602 former IPL General Service class customers are classified as Large C&I customers by MERC's initial proposal, increasing their customer charge from $5.00 per month to $45 per month in that initial proposal.[815]

636. Both the Department and the OAG recognize the need to increase the monthly charge for former IPL Residential customers in order to phase these customers into MERC's rate structure. However, both opposed MERC's proposal to increase the customer charge for all Residential customers to $11.00 per month and Small C&I to $20 per month.[816]

637. The OAG recommended maintaining the existing $9.50 customer charge for non-IPL Residential customers and moving the former IPL customers closer to that charge over the course of three rate cases. Under the OAG proposal, the former IPL Residential customer charge would be set at $6.50 in this rate case, increased to $8.00 in MERC's next rate case, and finally set at $9.50 in MERC's third rate case.[817] The OAG maintains that its three step approach is reasonable and will minimize the potential rate shock that former IPL customers may experience in response to the customer charge increases.[818]

814 Ex. 405 at 23 (Peirce Direct) (*citing* MERC Response to DOC IR No. 314).
815 Ex. 405 at 23 (Peirce Direct).
816 Ex. 405 at 19 (Peirce Direct); Ex. 304 at 35 (Nelson Direct).
817 Ex. 304 at 35 (Nelson Direct).
818 Ex. 304 at 34 (Nelson Direct).

638. The OAG also disputed MERC's proposed customer charge increase for former IPL small C&I customers and recommended instead increasing that customer charge to only $9 per month. The OAG asserts that this $4 increase is reasonable and higher than any of the customer charge increases recently approved by the Commission.[819] Finally, the OAG recommended decreasing the Small C&I customer charge for non-IPL customers by $1.00 to $17.00 per month.[820]

639. The OAG asserted that its recommended monthly customer charges are supported by economic theory and academic research on rate design that urges adoption of customer charges that reflect only the direct customer-specific costs of adding one more customer to the distribution system – i.e., the costs of a service line, a regulator, a meter, meter reading, and account administration.[821] Depending on which specific costs were included, the OAG's witness determined the monthly "customer specific" costs for former IPL Residential customers ranges from as low as $3.28 to as high as $10.41.[822] The OAG maintained that its recommended customer charge of $6.50 for former IPL Residential customers is appropriate as it is almost exactly half-way between the high and low estimate of the customer-specific costs, as is its recommendation of a $9 customer charge for former IPL small businesses.[823] As for the non-IPL Small C&I customer charge, the OAG contended that MERC's current customer charge of $18 per month is over-collecting customer-specific costs. The OAG maintained that the customer-specific costs associated with the Small C&I class are between $5 and $13.[824] The OAG asserted that decreasing this charge by $1 will be gradual enough to correct the over-collection without causing a large financial impact on MERC.[825]

640. MERC objected to the OAG's recommendation to transition the former IPL customers over three rate cases because, in MERC's view, such an approach would result in MERC's non-IPL customers continuing to subsidize the former IPL customers over a number of years.[826]

641. MERC also asserted that OAG's analysis of "minimum" and "maximum" customer-specific costs arbitrarily excludes a number of fixed costs caused by customers on MERC's system, which traditionally have been widely accepted as costs that should be recovered through the monthly customer charge.[827] Specifically, the OAG's analysis: does not include service lines in the minimum estimate; excludes 50 percent of expense related to customer records and collection expense in both the minimum and maximum estimates; and omits other costs such as vehicles, tools, and equipment that are needed

[819] *See* OAG Initial Br. at 49-50 (June 29, 2016) (eDocket No. 20166-122790-01).
[820] Ex. 304 at 55-56 (Nelson Direct).
[821] Ex. 304 at 46-52 (Nelson Direct).
[822] Ex. 304 at 51-52, Table 7 (Nelson Direct).
[823] OAG Initial Br. at 54 (June 29, 2016) (eDocket No. 20166-122790-01).
[824] Ex. 304 at 54 (Nelson Direct).
[825] Ex. 304 at 56 (Nelson Direct).
[826] Ex. 39 at 22-24 (Lee Rebuttal).
[827] Ex. 39 at 25-26 (Lee Rebuttal); Ex. 35 at 56-60 (Hoffman Malueg Rebuttal); MERC InitialBr. at 60-63 (June 29, 2016) (eDocket No. 20166-122788-01).

in the maintenance and operation of meters and service lines, as well as office equipment that is needed regardless of system volume.[828]

642. MERC noted that a service line is required to provide service to its customers and that typically there is a one-for-one relationship of service line to customer.[829] MERC also asserted that exclusion of these cost items is inconsistent with the *NARUC Gas Manual* regarding the costs to be included for recovery via the monthly customer charge.[830] According to the NARUC Gas Manual:

> The basis for the customer charge is that there are certain fixed costs that each customer should bear whether any gas is used at all. Examples of such costs are those associated with a service line, a regulator and a meter, recurring meter reading expenses, and administrative costs of servicing the account.[831]

643. Like the OAG, the Department also recommended increasing the monthly customer charge for former IPL Residential customers from $5.00 to $6.50, and maintaining the existing $9.50 Residential customer charge for all other Residential customers. While the Department acknowledged that reducing intra-class subsidies by moving customer charges closer to customer costs is an appropriate goal, it maintained that holding customer charges for non-IPL customers steady and raising former IPL customer charges to $6.50 would narrow the differences between the two rates while lessening the potential for rate shock.[832] The Department also suggested that the Commission consider increasing the Residential customer charge slightly over a period of several years with the goal of eventually establishing the same customer charge for all Residential customers.[833] The Department maintained that this proposal balances the goal of establishing cost-based rates with the goal of achieving a moderate impact to customer bills.[834]

644. In addition, the Department recommended holding the Sales class customer charges constant for MERC's former IPL customers. The Department's witness, Ms. Peirce, noted that typically in rate cases, she recommends a small increase in the customer charge to move customer charges closer to customer costs, but in this case she recommended holding the customer charges for sales customers to their current level to narrow the customer charge rate difference between the former IPL customer and the rest of MERC's customers.[835]

645. In Rebuttal Testimony, MERC acknowledged the OAG's and Department's concerns regarding the potential for rate shock to the former IPL customers under

[828] Ex. 35 at 56-57 (Hoffman Malueg Rebuttal).
[829] Ex. 35 at 56 (Hoffman Malueg Rebuttal).
[830] MERC Initial Br. at 61 (June 29, 2016) (eDocket No. 20166-122788-01).
[831] MERC Initial Br. at 61 (June 29, 2016) (eDocket No. 20166-122788-01) (*citing* NARUC Gas Distribution Rate Design Manual at 12).
[832] Ex. 405 at 20-21 (Peirce Direct).
[833] Ex. 405 at 20-21 (Peirce Direct).
[834] Ex. 405 at 22 (Peirce Direct).
[835] Ex. 405 at 20 (Peirce Direct).

MERC's initial proposal. In response, MERC proposed to hold all existing non-IPL customers to their current customer charges and to move the former IPL customers to the midpoint between their existing customer charge and MERC's current customer charge.[836]

646. Under MERC's revised proposal, the Residential customer charge for non-IPL customers would remain at $9.50, while the charge for former IPL Residential customers would increase to $7.25 (halfway between $5.00 and $9.50). The customer charge for non-IPL Small C&I customers would remain at $18.00 per month, while the customer charge for former IPL Small C&I customers would increase to $11.50 per month. Large C&I customers would remain at $45 per month. MERC requested that the Commission order that the former IPL customers be fully transitioned to MERC customer charges in MERC's next rate case.[837]

647. In Surrebuttal Testimony, the Department did not object to MERC's current proposal, but deferred to the Commission to decide whether a smaller increase in the Residential customer charge to $6.50 for former IPL customers is warranted at this time. The Department recommended adoption of MERC's proposed customer charges for the remaining classes.[838]

648. The OAG did not agree with MERC's revised proposal and continued to recommend its initial proposal.[839]

649. The table below summarizes MERC's existing and final proposed customer charges, along with the Department's and OAG's final proposed customer charges.[840]

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[836] Ex. 39 at 16-17 (Lee Rebuttal); Ex. 406 at 5 (Peirce Surrebuttal).
[837] Ex. 39 at 17 (Lee Rebuttal).
[838] Ex. 406 at 5-6 (Peirce Surrebuttal).
[839] Ex. 307 at 22 (Nelson Surrebuttal).
[840] Ex. 406 at 5 (Peirce Surrebuttal); Ex. 39 at 16-17 (Lee Rebuttal); Ex. 37, ASL-1, Schedule 1 (Lee Direct); Ex. 406 at 5 (Peirce Direct); Ex. 304 at 55 (Nelson Direct); OAG's Initial Br. at 49-50 (June 29, 2016) (eDocket No. 20166-122790-01).

Current and Proposed Customer Charges

Customer Class	MERC Current	MERC Proposed	DOC Proposal	OAG Proposal
Residential:				
Existing MERC	$9.50	$9.50	$9.50	$9.50
Former IPL	$5.00	$7.25	$7.25/$6.50	$6.50
GS – SC&I:				
Existing MERC	$18.00	$18.00	$18.00	$17.00
Former IPL	$5.00	$11.50	$11.50	$9.00
GS-LC&I:				
Existing MERC	$45.00	$45.00	$45.00	
Former IPL	$5.00	$25.00	$25.00	
SVI & SVJ-Sales:				
Existing MERC	$165.00	$165.00	$165.00	
Former IPL	$14.00	$89.50	$89.50	
LVI & LVJ-Sales:				
Existing MERC	$185.00	$185.00	$185.00	
Former IPL	$14.00	$99.50	$99.50	
SVI & SVJ – Transport				
Existing MERC	$275.00	$280.00	$280.00	
Former IPL	$210.00	$280.00	$280.00	
LVI&LVJ – Transport				
Existing MERC	$295.00	$300.00	$300.00	
Former IPL	$210.00	$300.00	$300.00	
Flex Rate	$295.00	$300.00	$300.00	
SLVI	$460.00	$470.00	$470.00	

650. As the chart above shows, MERC's revised proposal is the same as the Department's proposal, except that the Department did not make a final recommendation on the Residential customer charge for former IPL customers. The OAG's proposal, however, calls for lower customer charges for former IPL customers in the Residential Class and for all customers in the Small C&I class.

651. The Department also recommended that MERC be directed to provide information to the former IPL customers on its Conservation Improvement Program (CIP) offerings, Low Income Heating Assistance Program (LIHEAP) availability, and Gas Affordability Program (GAP), and requested that MERC provide additional information about how it intends to inform customers of these program offerings. [841]

[841] Ex. 405 at 24 (Peirce Direct).

652. In its response, MERC stated that it has and will continue to provide its former IPL customers the same bill inserts and direct mailings regarding its CIP, GAP and Energy Assistance programs that it provides to its other MERC customers.[842]

653. In considering which rate design to recommend, the Administrative Law Judge recognizes that moving classes closer to cost is consistent with the rate design principle that rates should promote efficient use of resources and minimize inter-class subsidies.[843] Minimizing inter-class subsidies is perceived to be "fair" to all ratepayers and it gives customers accurate information (or "price signals") about the cost of energy.

654. However, when setting rates other concerns need to be balanced including promoting intra-class equity and minimizing rate shock that certain customers may experience in response to a large, sudden change in the fixed monthly charge.[844]

655. The Administrative Law Judge concludes that MERC's proposal to hold all existing non-IPL customers to their current customer charges and to move the former IPL customers to the midpoint between their existing customer charge and MERC's current customer charge is reasonable and appropriately balances concerns about rate shock to the former IPL customers with the other rate design principles.

656. The Administrative Law Judge finds that MERC's proposal to increase the Residential customer charge for former IPL customers to $7.25 per month to begin the process of moving the IPL customers closer to the cost of service and reduce intra-class subsidies is appropriate and recommends the Commission adopt it. Although a $2.25 increase in the monthly charge will be significant for the former IPL customers, these customers have not had a rate increase in 20 years (since 1996) and are currently being charged rates well below the cost of providing them service.[845] Moreover, a $7.25 per month customer charge is below both Xcel's $9.00 per month Residential gas customer charge,[846] and CenterPoint's $9.50 per month Residential customer charge.[847]

657. MERC's request to move the former IPL customers to the midpoint between their existing customer charge and MERC's current Residential customer charges is reasonable. The proposed $7.25 rate for the former IPL Residential customers will reduce further subsidization of costs by MERC's other customers and provide a sufficient economic price signal to encourage energy conservation, while still being small enough to minimize the potential for rate shock.

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[842] Ex. 39 at 19-21 (Lee Rebuttal).
[843] 2013 MERC RATE CASE ORDER at 52.
[844] 2013 MERC RATE CASE ORDER at 51-52.
[845] Ex. 35 at 52-55, JCHM-R3 (Hoffman Malueg Rebuttal).
[846] *See In the Matter of the Application of Northern States Power Company, a Minnesota Corporation, for Authority to Increase Rates for Natural Gas Service in Minnesota,* MPUC Docket No. G-002/GR-09-1153, FINDINGS OF FACT, CONCLUSIONS AND ORDER at 35 (Dec. 6, 2010).
[847] *See In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota*, MPUC Docket G-008/GR-15-424, FINDINGS OF FACT, CONCLUSIONS AND ORDER at 64-65 (June 3, 2016).

658. The Administrative Law Judge does not recommend adopting the OAG's proposal to transition the former IPL customers to the MERC customer charge over the course of three rate cases. The OAG's proposal would result in MERC's non-IPL customers continuing to subsidize MERC's IPL customers over a number of years. Such a long transition would result in unreasonably preferential rates for the former IPL customers who receive the same service and are in the same class of service as MERC's other customers. The Administrative Law Judge recommends instead that the Commission order that the former IPL customers be fully transitioned to MERC customer charges in the Company's next rate case.

659. In summary, the Administrative Law Judge finds that MERC's proposed customer charges as recommended in its Rebuttal Testimony best balance the interests relevant to establishing just and reasonable rates and should be approved.

X. Other Issues - Disputed

A. Decoupling

660. Decoupling is a "regulatory tool designed to separate a utility's revenue from changes in energy sales."[848] In general, a revenue decoupling mechanism (RDM) is a revenue true-up that revises energy rates to recover differences between actual and forecasted base class revenue responsibility.[849] The true-up decreases or increases energy rates charged to customers if their collective usage during a given time period deviates from a set base amount.[850]

661. In reviewing decoupling programs, the Commission considers whether the decoupling mechanism: (1) will reduce a utility's disincentive to promote energy efficiency, (2) is consistent with statutory energy savings goals, and (3) will adversely affect utility ratepayers.[851]

662. MERC's current RDM is a full decoupling[852] pilot program approved by the Commission as part of the 2010 MERC rate case.[853] The program applies to the Residential and Small C&I customer classes only, and contains a symmetrical 10 percent cap on revenues generated through application of the RDM.[854]

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[848] Minn. Stat. § 216B.2412, subd. 1 (2016).
[849] Ex. 402 at 2 (Davis Direct).
[850] Ex. 402 at 2 (Davis Direct).
[851] Minn. Stat. § 216B.2412, subd. 2 (2016).
[852] A full decoupling mechanism is one where the true-up amount is based on differences between forecasted revenue and actual sales that occur regardless of the reason, including weather deviations. Ex. 402 at 2 (Davis Direct).
[853] *In the Matter of the Application of Minn. Energy Res. Corp. for Auth. To Increase Rates for Natural Gas Serv. in Minn.*, MPUC G-007, 011/GR-10-977, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 12-15 (July 13, 2012) (2010 MERC ORDER).
[854] 2010 MERC ORDER at 12.

663. The pilot program became effective on January 1, 2013, and was scheduled to end on December 31, 2015.[855] On August 11, 2015, the Commission indefinitely extended the time period for MERC's decoupling pilot program.[856]

664. In this case, MERC seeks extension of the current decoupling pilot program for another three years with the symmetrical cap currently in place, but does not support including additional customer classes in the program.[857] MERC argued that the structure of the rate classes and rate design makes application of the current RDM to large industrial classes impracticable.[858] With regard to the current symmetrical cap, MERC is willing to remove the cap entirely, but claims implementation of an asymmetrical cap would be an undue burden.[859] According to MERC, it would rather terminate the decoupling program entirely rather than have an asymmetrical cap imposed.[860]

665. At the outset of this proceeding, the Department asked MERC to provide an update on its 2015 CIP achievements in order to analyze the impact of the decoupling pilot program on energy savings.[861] MERC provided the requested update regarding its 2015 CIP achievements.[862] According to the Department's analysis of MERC's 2010-2015 CIP data, MERC has demonstrated overall energy savings during the time the decoupling pilot program has been in place. The Department noted, however, that MERC's Residential energy savings have declined more than 15 percent since the decoupling program was first instituted in 2013.[863]

666. The Department agreed with MERC's request to have its current decoupling pilot program extended for another three years.[864] The Department did not support extending the decoupling program to additional customer classes at this time because the record does not show that MERC has a throughput incentive[865] to increase sales to its larger customer classes.[866] With regard to the cap, the Department initially recommended application of an asymmetrical cap to MERC's decoupling program to ensure adequate ratepayer protection.[867] However, upon review of information acquired during discovery, the Department concluded it is reasonable for MERC's decoupling

[855] 2010 MERC ORDER at 12-15.
[856] *In the Matter of the Application of Minn. Energy Res. Corp. for Auth. To Increase Rates for Natural Gas Serv. in Minn.*, MPUC G-007, 011/GR-10-977, ORDER at 1 (Aug. 11, 2015).
[857] Ex. 41 at 74 (DeMerritt Direct).
[858] Ex. 41 at 78 (DeMerritt Direct).
[859] Ex. 41 at 79-80 (DeMerritt Direct).
[860] Ex. 41 at 73 (DeMerritt Direct).
[861] Ex. 402 at 16 (Davis Direct).
[862] Ex. 39 at 32 (Lee Rebuttal).
[863] Ex. 403 at 3-5 (Davis Surrebuttal).
[864] Ex. 403 at 14 (Davis Surrebuttal).
[865] Because of the high fixed costs associated with the natural gas and electric utility industries, a utility's marginal revenue often exceeds its short-run marginal costs, giving a utility an incentive to increase sales. This phenomenon is referred to as the "throughput incentive." Ex. 402 at 6 (Davis Direct).
[866] Ex. 403 at 14 (Davis Surrebuttal).
[867] Ex. 402 at 16 (Davis Direct).

program to maintain a symmetrical cap for now because an asymmetrical cap could undermine MERC's disincentive to encourage energy savings.[868]

667. While the Department supported extending MERC's decoupling program in its current form, the Department did recommend additional reporting by MERC regarding these issues. The Department suggested that MERC be required, in its next rate case, to demonstrate why extending decoupling to all customer classes with more than 50 customers is not reasonable, and also address evidence showing energy savings for Residential customers has decreased since inception of the decoupling pilot program.[869]

668. MERC agreed with the Department's recommendation for future reporting requirements.[870]

669. The OAG did not support continuation of MERC's decoupling program in its current form. The OAG disagreed with the Department's assessment of MERC's decoupling program. The OAG maintained that MERC did not present sufficient quantitative analysis to demonstrate decoupling could be detrimental to large industrial customer classes with a small number of customers. The OAG also asserted that the Department's throughput analysis was unreliable. In addition, OAG maintained that MERC has not demonstrated that its decoupling program will benefit ratepayers.[871]

670. As a result, the OAG recommended that the following changes be applied to MERC's decoupling pilot program if extended: (1) all customer classes with more than 50 customers should be decoupled; (2) MERC must achieve 1.2 percent energy savings through its conservation improvement programs to administer any surcharges via the decoupling program; and (3) MERC should not be allowed to increase the Residential or Small Business classes' customer charges.[872]

671. MERC disagreed with the OAG's position regarding its decoupling program. First, MERC claimed extension of decoupling to additional customer classes would have unintended negative consequences outweighing any possible benefits.[873] MERC pointed out that when the Commission originally approved MERC's decoupling pilot program, the Commission determined that MERC lacks the same throughput incentive for large customer classes as small customer classes.[874] Second, MERC asserted allowing surcharges only upon achievement of a 1.2 percent energy savings threshold is not reasonable because many variables unrelated to decoupling affect MERC's energy savings.[875] MERC pointed out that the Commission has previously refused to make decoupling contingent on achieving a specific energy savings result.[876] Third, MERC asserted the proposed customer charges for the Residential and Small C&I classes do

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868 Ex. 403 at 8-9 (David Surrebuttal).
869 Ex. 403 at 14-15 (Davis Surrebuttal).
870 Tr. Vol. 1 at 85 (Lee).
871 Ex. 306 at 1-13 (Nelson Rebuttal).
872 Ex. 306 at 12-13 (Nelson Rebuttal).
873 Ex. 40 at 8-9 (Lee Surrebuttal).
874 2010 MERC ORDER at 14.
875 Ex. 40 at 17-18 (Lee Surrebuttal).
876 2010 MERC ORDER at 13-14.

not fully cover the customer-related fixed costs of providing services, which MERC incurs regardless of whether the customer uses any gas.[877] According to MERC, setting customer charges below the fixed cost of providing service gives inaccurate price signals to customers and increases intra-class subsidies.[878]

672. The Administrative Law Judge concludes that continuation of MERC's current decoupling pilot program for another three years in its current form is reasonable and appropriate. MERC's current decoupling pilot program has been approved and indefinitely extended by the Commission, and evidence presented during this proceeding has not proven an urgent need to change or eliminate the program.

673. With regard to the OAG's proposal in particular, the Administrative Law Judge already has recommended that MERC's customer charges remain the same for all MERC customers at least until the next rate case, except for the former IPL customers. In terms of the other two aspects of the OAG's proposal (extending decoupling to other classes and tying decoupling to meeting an energy savings goal), the Administrative Law Judge recognizes that the Commission has already denied similar requests in prior decisions.

674. However, the Administrative Law Judge agrees with the Department and the OAG that MERC should be required in its next rate case to demonstrate why extending decoupling to all customer classes is not reasonable. The Administrative Law Judge also agrees with the Department that MERC should be required in its next rate case to address evidence showing Residential energy savings has decreased since inception of the decoupling pilot program.

B. Notice Requirements for Switching to and from Transportation Service

675. MERC's existing tariff includes notice requirements customers who seek to switch to sales service from transportation service and vice versa. Under the 3rd Revised Sheet No. 6.01 of MERC's tariff:

> Customers may transfer to Transportation Service for the period November 1 through October 31 after giving the Company ninety days advance notice prior to November 1. A transportation customer must maintain transportation service for the entire November through October period. A transportation customer may not return to sales service until the next November 1st and must notify the Company in writing at least ninety days prior to the transfer. A customer may only transfer to firm sales service if Company is able to arrange adequate firm gas entitlements to meet the needs imposed on its system by the customer, without jeopardizing system reliability or increasing costs for its customers.[879]

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[877] Ex. 40 at 19 (Lee Surrebuttal).
[878] Ex. 40 at 19 (Lee Surrebuttal).
[879] Ex. 200 at 10-11 (Sorenson Direct) (quoting MERC's 3rd Revised Sheet No. 6.01).

676. Constellation maintains that the current tariff is unduly restrictive and more flexibility is needed for customers when their circumstances change unexpectedly.[880]

677. Constellation provided an example of a transportation customer whose business experienced financial hardship. The customer's gas consumption dropped dramatically as it ceased operations, but it needed to maintain a minimal amount of heat at its building while it was trying to sell the facility. At that point, the lower volumes no longer warranted gas transportation service and the customer wanted to switch to MERC's sales service. However, the customer made the decision in late summer. Constellation was willing to release the customer, but MERC would not accept the customer as a sales customer at that point because the August 1 deadline for providing the 90-day notice had already passed.[881] As a result, the customer had to remain on transportation service, paying the additional costs of that service, for more than a year.[882]

678. To address situations like this, Constellation proposed that MERC modify its tariff language to provide more flexibility in the notice required to switch services. More specifically, Constellation proposed that MERC add language similar to that found in the tariff of MERC's affiliate Wisconsin Public Service Corporation (WPS), which provides that the existing notice requirements in the tariff may be waived:

> [in the Company's sole discretion, if the Company has adequate gas supply and interstate pipeline capacity to serve the customer, and the Company anticipates no significant detriment to existing system sales customers. If the Company waives the notice requirement, the Company may require the customer to pay an exit fee to recover the costs related to a switch to or from service under this rate schedule. This exit fee may include, but is not limited to, any above market gas commodity costs, any interstate pipeline transportation and/or storage costs, and any other demand costs.[883]

679. Constellation maintained that this or similar language would give MERC the ability, at its sole discretion, to waive the notice requirements without harming MERC or its customers.[884]

680. Constellation also proposed that MERC's tariff be modified: to allow 30-days' notice, rather than 90-days' notice, when notice is provided between April 1 and July 31 (outside of the heating season); to allow the move from sales service to transportation service on the first day of any month between April 1 and July 31; and to provide that the one-year restriction from switching be a rolling one-year period rather than the November 1 through October 31 time frame currently included in the tariff.[885]

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[880] Ex. 202 (Sorenson Testimony Summary).
[881] Ex. 200 at 11 (Sorenson Direct); Ex. 201 at 8 (Sorenson Surrebuttal).
[882] Ex. 201 at 8 (Sorenson Surrebuttal).
[883] Ex. 200 at 12 (Sorenson Direct).
[884] Ex. 200 at 12 (Sorenson Direct).
[885] Ex. 200 at 12 (Sorenson Direct).

681. MERC opposed Constellation's proposed notice changes and recommended the changes be rejected by the Commission. According to MERC, the 90-day notice requirement is necessary to ensure MERC has adequate time to make account changes, install and test telemetry equipment, perform gas meter modifications, make billing system changes, and allow for changes to demand entitlements.[886]

682. In addition, MERC emphasized that it is required to submit an annual demand entitlement filing every year on November 1, identifying the amount of firm pipeline capacity to be purchased for the upcoming November through October time period.[887]

683. According to MERC, "shortening the notification period or allowing unplanned switches from the Firm rate schedule to the Transportation Gas schedule outside of the required November through October time period could cause harm, in the form of stranded pipeline capacity costs, to those customers remaining on the Firm rate schedule. Conversely, shortening the notification period or allowing unplanned switches from the Transportation Gas rate schedule to the Firm rate schedule could cause harm by decreasing the amount of winter capacity available to customers on the firm rate schedule, increasing the probability of gas supply interruptions."[888]

684. In addition, MERC stated that the WPS tariff includes the waiver language because WPS normally requires 245-days' notice for a customer to switch to or from systems sales service. In MERC's view, because its notice period is much shorter (90 days), the waiver language proposed by Constellation is unnecessary.[889]

685. In Surrebuttal Testimony, Constellation reiterated that its waiver proposal is intended to apply only if there is no detriment to sales customers and any waiver would be at the sole discretion of MERC. Constellation also asserted that MERC mistakenly interpreted its waiver proposal to prohibit MERC from continuing to require 90-days' notice. In addition, Constellation clarified that while it proposed using the WPS tariff language, it is willing to entertain alternative tariff language.[890]

686. The Administrative Law Judge concludes the record supports Constellation's proposal to allow MERC the discretion to grant a waiver of the notice provisions to address unique circumstances facing a customer, where doing so would have no detriment to existing sales customers. Constellation has provided evidence of a situation where a waiver of the August 1 deadline would have been justified for a customer facing unforeseen financial difficulties. To be reasonable, however, the waiver must only be permitted where there is no detriment to existing system sales customers. The WPS tariff language proposed by Constellation is insufficient in this regard because it allows a waiver where the company "anticipates no **significant** detriment to existing system sales

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886 Ex. 39 at 47 (Lee Rebuttal).
887 Ex. 39 at 48 (Lee Rebuttal).
888 Ex. 39 at 48 (Lee Rebuttal).
889 Ex. 39 at 48-49 (Lee Rebuttal).
890 Ex. 201 at 7 (Sorenson Surrebuttal).

customers."[891] Thus, the WPS language allows some detriment, just not a "significant detriment." In addition, in the view of the Administrative Law Judge, the WPS language is also insufficient because it is not limited to customers facing unforeseen circumstances. The waiver should be limited to customers facing unforeseen circumstances so that it is not used by customers who could have requested a waiver prior to the normal August 1 deadline. If the Commission agrees, the Commission should require the Company either to revise the WPS language or propose new language consistent with this recommendation as part of a compliance filing.

687. With regard to Constellation's other proposed revisions to the existing notice requirements set forth in paragraph 680 above, the Administrative Law Judge agrees with MERC that Constellation's proposals are not supported by the record. MERC has shown a 90-day notice period is generally necessary. MERC has also provided evidence to support the November 1 to October 30 service requirement.[892] Moreover, if waiver language is added to the tariff, it is unnecessary to further revise the existing language to address these concerns because customers facing unforeseen circumstances will be able to request a waiver.

C. Non-Telemetered Small Volume Transportation Service

688. Prior to its 2008 rate case, MERC allowed Small Volume transportation service customers to pay a volumetric balancing fee in lieu of installing the telemetry equipment otherwise required by its tariff.[893]

689. In MERC's 2008 rate case, the Company proposed to stop offering small volume balancing service to its transportation customers and to instead require these customers to install telemetry equipment.[894] Telemetry equipment allows MERC and transportation customers to more accurately and efficiently monitor a customer's natural gas usage and the sufficiency of the customer's purchased supply.[895]

690. In its 2008 Order, the Commission approved the request. The Commission explained its decision as follows:

> The cost of telemetry equipment is not exorbitant and does not, even in the near term, exceed the cost of the balancing services Small Volume customers are currently purchasing; the one-time cost of telemetry equipment is comparable to the recurring, annual cost of balancing services. Second, the Company offers favorable financing plans for the purchase of telemetry equipment, which the Commission will require it to continue. Further, the precision that telemetry offers will enable both

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[891] Ex. 200 at 12, SS-6 (Sorenson Direct) (emphasis added).
[892] *See* Ex. 39 at 47-48 (Lee Rebuttal).
[893] Ex. 200 at 5 (Sorenson Direct).
[894] *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, MPUC Docket No. G-007-08-835, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 17 (June 29, 2009) (2008 MERC ORDER).
[895] 2008 MERC ORDER at 17.

customers and Company to manage their natural gas supplies more efficiently and cost-effectively.[896]

691. According to Constellation, the Commission's decision in the 2008 rate case had the unintended consequence making small volume transportation service unaffordable for many customers.[897] In support of its position, Constellation noted that it provided natural gas commodity and related services to approximately 138 Small Volume customers before telemetry was required. After telemetry was required, approximately 100 of Constellation's customers stopped taking service. Constellation asserted that these customers no longer found it feasible to purchase their natural gas commodity competitively due to the additional costs and requirements associated with telemetering.[898]

692. Constellation pointed out that MERC charges to install telemetry equipment. The cost ranges between $905 and $2,250, with an average cost of approximately $1,100 per installation. The cost varies based upon the equipment and time associated with its installation.[899]

693. Constellation requested that the Company be required to submit a proposed tariff for a Small Volume non-telemetered program in its next rate case or within three years following the final order in this proceeding, whichever is earlier. Constellation also requested that the Commission require the Company to work collaboratively with interested third party suppliers and customers in developing the proposal.[900] Constellation believes that with a properly structured tariff and appropriate monthly balancing fee, non-transportation tariff ratepayers would not be affected by lack of telemetry requirement for Small Volume customers.[901]

694. Constellation noted that several other natural gas local distribution companies, including former MERC affiliates in Iowa and Nebraska, provide non-telemetered transportation options for commercial customers.[902] Constellation highlighted those in Iowa and South Dakota because "these non-telemetered services operate at utilities that are located behind the same natural gas pipelines as those that serve MERC, specifically Northern Natural Gas and Northern Border Pipeline Co."[903]

695. MERC opposed Constellation's request for a non-telemetered Small Volume transportation program because it would require significant changes to MERC's gas supply, transportation, and billing areas. MERC also claimed that such a program would "undermine the benefits from MERC's telemetry program."[904]

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[896] *Id.* at 17-18.
[897] Ex. 200 at 5-6 (Sorenson Direct); Ex. 201 at 3 (Sorenson Surrebuttal).
[898] Ex. 200 at 5-6 (Sorenson Direct).
[899] Ex. 200 at 6 (Sorenson Direct).
[900] Ex. 200 at 9 (Sorenson Direct).
[901] Ex. 200 at 6 (Sorenson Direct).
[902] Ex. 200 at 6 (Sorenson Direct).
[903] Ex. 200 at 7 (Sorenson Direct).
[904] Ex. 39 at 43 (Lee Rebuttal).

696. MERC currently requires all interruptible customers to install telemetry equipment. In practice, use of telemetry has improved MERC's ability to manage natural gas supply more efficiently and cost-effectively.[905] In its pending Demand Entitlement docket, Commission staff noted that staff believes "the daily interruptible data availability enhanced MERC's ability to calculate its [design day] requirements, which led to the capacity reduction. The annual reduction provides MERC ratepayers with approximate savings of $1.1 million."[906]

697. In MERC's view, providing a Small Volume non-telemetered gas transportation program would undermine these benefits and would result in increased costs.[907] For these reasons, MERC opposed Constellation's proposal. If, however, the Commission believes a further evaluation of such a program is desirable, MERC suggested that such a program be considered in a separate docket, apart from a rate case.[908]

698. Based on a review of the record, the Administrative Law Judge concludes that Constellation has not provided sufficient evidence to support its proposal for a non-telemetered Small Volume transportation program. While Constellation claims that the telemetry requirement has made transportation service unaffordable for many Small Volume customers, Constellation's claim is based solely on its loss of commodity customers after the telemetry requirement was adopted. There is no specific evidence in the record from any of these customers to show that the cost of the telemetry equipment, which averages $1,100, made the transportation service unaffordable. While such cost evidence of may exist, Constellation has not offered any such evidence into the record. Similarly, Constellation's reliance on programs from other states, without more, does not show that such programs are more reasonable than MERC's requirement of telemetry for all interruptible transportation customers. In contrast, the record shows that MERC's telemetry program has improved MERC's ability to manage its natural gas supply more efficiently and cost-effectively, resulting in approximate savings of $1.1 million for MERC's customers.[909]

699. For these reasons, the Administrative Law Judge recommends that the Commission take no action on Constellation's proposal at this time. If Constellation is able to develop additional evidence to support its proposal, it could file a separate petition with the Commission or include its proposal in MERC's next rate case.

D. Transportation Imbalance Process

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[905] Ex. 39 at 44 (Lee Rebuttal).
[906] *In the Matter of Petitioners by Minnesota Energy Resources Corporation (MERC-Consolidated, MERC-NNG- and MERC-Albert Lea) for Approval of Changes in Contract Demand Entitlements for the 2015-2016 Heating Season Supply Plan Effective November 1, 2015,* MPUC Docket Nos. G011/M-15-722, G011/M-15-723, G011/M-15-724, MINNESOTA PUBLIC UTILITIES COMMISSION STAFF BRIEFING PAPERS at 8-9 (April 5, 2016).
[907] Ex. 39 at 44 (Lee Rebuttal).
[908] Ex. 39 at 44-45 (Lee Rebuttal).
[909] Ex. 201 at 4-5 (Sorenson Rebuttal).

700. On January 5-7, and January 25-29, 2014, MERC curtailed all gas service to Interruptible and Joint Service transportation customers to ensure continued delivery of natural gas to firm customers.[910]

701. During this time period, the market value of the gas ranged from a low of $6.750 MMBtu to a high of $53.305 MMBtu.[911]

702. MERC used its current imbalance process to return the volume of gas through an infield transfer on March 13, 2014, when the market price of gas was $5.140 per MMBtu.[912]

703. MERC's current imbalance process addresses both situations where a transportation customer overnominates and does not utilize all of the gas, as well as situation where a customer undernominates and utilizes more gas than is delivered. MERC's current imbalance process largely mirrors the NNG imbalance calculation method.[913]

704. Constellation has proposed new tariff language that would apply when curtailments are made on a Critical Day or when an Operational Flow Order (OFO) is declared, specifying a new method for compensating transportation customers in these circumstances.[914] Under Constellation's proposal, the price that would be paid under such circumstances would be equal to the price of gas at the time MERC provided notice of the Critical Day as reported in Platt's Gas Daily as "Midpoint for Chicago Citygates" under the Citygates section of Platts *Gas Daily* plus 10%.[915]

705. Constellation also proposed that MERC be required to post on its website information regarding each Critical Day or OFO called, including the date of the event, the duration and geographic boundaries of the event, and an explanation of the underlying cause or causes of the event.[916]

706. MERC did not agree with either recommendation.[917]

707. MERC disagreed with the recommendation that it revise its current imbalance process. First, MERC contended that its existing monthly imbalance process is designed to fairly balance situations of over-nomination or under-nomination and that its existing tariff provides a number of reasonable alternatives for transportation customers in the event a curtailment is called.[918] For example, transportation customers may elect either an imbalance cash out or infield transfer to storage for monthly balances. In addition, transportation customers may make an intraday nomination of gas after a

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[910] Ex. 200 at 13 (Sorenson Direct); Ex. 39 at 50 (Lee Rebuttal).
[911] Ex. 201 at 11 (Sorenson Surrebuttal)
[912] Ex. 201 at 11 (Sorenson Surrebuttal).
[913] Tr. Vol. 1 at 156 (Sorenson).
[914] Ex. 202 (Sorenson Opening Statement).
[915] Ex. 202 (Sorenson Opening Statement).
[916] Ex. 200 at 15-16 (Sorenson Direct).
[917] Ex. 39 at 50-51 (Lee Rebuttal).
[918] Ex. 39 at 50 (Lee Rebuttal).

curtailment is called, and customers who are called upon to curtail may elect to continue to utilize natural gas, subject to curtailment penalties.[919]

708. Second, MERC maintained that Constellation's suggested tariff revisions would allow marketers, such as Constellation, to effectively game the imbalance process in order to achieve a windfall for over-and-under designated gas. MERC asserted that its methodology for calculating the monthly cashout for its customers who receive service on the NNG pipeline largely mirrors NNG's cashout calculation methodology in order to avoid opportunities for parties to try to manipulate the imbalance process.[920]

709. MERC also disagreed with the recommendation to post information regarding each Critical Day or OFO called on the Company's website because MERC notifies affected customers of curtailment start and end times directly. MERC asserted that this process is sufficient to ensure customers are informed of curtailment events and that publishing additional information on the Company's website could lead to potential customer confusion.[921]

710. The Administrative Law Judge finds that the Constellation's proposed changes to MERC's tariff are unnecessary and that MERC's existing imbalance process is reasonable as MERC's existing tariff provides a number of alternatives for transportation customers in the event a curtailment is called. The Administrative Law Judge also agrees with MERC that Constellation's proposal that MERC publish information on its website regarding each Critical Day or OFO called is unnecessary given that affected customers are notified directly.

XI. Other Issues – Resolved

A. Small Volume Firm Transportation Service

711. Constellation initially recommended that MERC reevaluate its class of service options for transportation service and investigate the feasibility and market propensity for a small volume firm transportation service option.[922]

712. MERC disagreed with Constellation's recommendation.[923]

713. In response to discovery, MERC stated that its joint service tariffs allow a transportation customer to have 100 percent firm delivery of its third party gas supply from the city gate to the customer facility.[924]

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[919] Tr. Vol. 1 at 85 (Sorenson).
[920] MERC's Initial Br. at 84-85 (June 29, 2016) (eDocket No. 20166-12788-01).
[921] Ex. 39 at 51 (Lee Rebuttal).
[922] Ex. 200 at10 (Sorenson Direct).
[923] Ex. 39 at 45-46 (Lee Rebuttal).
[924] Ex. 201, Schedule SS-2 (Sorenson Surrebuttal).

714. Constellation agreed that MERC's Small and Large Volume Joint Service tariff meets small customer needs for a firm transportation service and determined that the issue was no longer contested.[925]

715. No other party offered testimony on this issue.

716. The Administrative Law Judge finds concludes that no Commission action is needed on this issue.

B. Joint Service Affidavit for Firm Transportation Customers

717. Constellation recommended the elimination, or at a minimum modification, of MERC's Joint Service Affidavit for Firm Transportation Customers. Constellation expressed concern that MERC currently requires both the marketer and the end-use customer to sign the form simultaneously before a notary, a time-consuming and costly task.[926]

718. MERC did not agree to eliminate the Joint Service Affidavit but did agree to modify the document such that the need for notarization is eliminated, and simultaneous customer and marketer signatures are no longer required, allowing for signatures to be made at separate times and locations.[927]

719. Constellation agreed with MERC's proposal to modify the Joint Service Affidavit.[928]

720. No other party offered testimony on this issue.

721. The Administrative Law Judge finds that MERC's proposed modification to its Joint Service Affidavit for Firm Transportation Customers as described in Rebuttal Testimony is reasonable and should be adopted.

C. Cost of Gas

722. MERC submitted a Petition for approval of a new Base Cost of Gas for interim rates, concurrently with its Initial Filing in this docket, using NYMEX data from May 15, 2015, as described in MERC's base cost of gas filing in Docket No. G011/MR-15-748.[929]

723. The Commission issued an Order Setting New Base Cost of Gas and Requiring Further Filings on November 30, 2015, approving an adjusted interim base cost of gas purchased gas adjustment and requiring MERC to recalculate and restate its purchased gas adjustment factors and resubmit its interim base cost of gas. The Commission's order further required that MERC provide updated information about the

[925] Ex. 201 at 6-7 (Sorenson Surrebuttal).
[926] Ex. 200 at 17-18 (Sorenson Direct).
[927] Ex. 39 at 53 (Lee Rebuttal).
[928] Ex. 201 at 18 (Sorenson Surrebuttal).
[929] Ex. 41 at 16 (DeMerritt Direct).

commodity base cost of gas during the course of the general rate case proceeding and work with the Department and Commission staff to determine the timing of its update.[930]

724. In Direct Testimony, the Department recommended that MERC be required to reduce its base cost of gas and revenues by $8,477,852, for a net effect on the revenue requirement of zero.[931]

725. MERC filed an update to the commodity cost of gas based on NYMEX prices as of March 15, 2016 on April 12, 2016, in accordance with the agreement of the parties.[932]

726. MERC agreed that an adjustment is appropriate to reflect the updated cost of gas and revenues and provided that the updated cost of gas as submitted on April 12, 2016, in this docket and Docket No. G011/MR-15-748, was the appropriate cost of gas to be used.[933] The update reflected a reduction to the cost of gas and revenues of $43,522,851 relative to MERC's original filing.[934]

727. The Department agreed with MERC's proposed adjustment.[935]

728. No other party offered testimony on this issue.

729. The Administrative Law Judge finds that the updated cost of gas filed on April 12, 2016 in this docket[936] should be used in the test year, decreasing PGA revenue and expense by $43,522,851 from MERC's originally filed figures.

D. Test Year

730. Minn. Stat. § 216B.16, subd. 3(a), requires interim rates to start within 60 days of the initial rate case filing. MERC's test year begins January 1, 2016. MERC filed its rate case on September 30, 2015 (93 days before January 1) and waived its right under the statute to have interim rates in effect not later than 60 days after the initial filing.[937]

731. In its Notice of and Order for Hearing issued November 30, 2015, the Commission ordered that the parties specifically and thoroughly address the question of whether the test year in this case and in future MERC rate cases should be so far removed

930 ORDER SETTING NEW BASE COST OF GAS AND REQUIRING FURTHER FILINGS at 4 (Nov. 30, 2015) (eDocket No. 201511-116012-02); *see also In the Matter of the Petition of Minn. Energy Res. Corp. for Approval of a New Base Cost of Gas to Coincide with Implementation of Interim Rates*, MPUC Docket No. G011/M-15-748, ORDER SETTING NEW BASE COST OF GAS AND REQUIRING FURTHER FILINGS at 4 (Nov. 30, 2015).
931 Ex. 416 at 40 (St. Pierre Direct).
932 COMPLIANCE FILING -- BASE COST OF GAS UPDATE (Apr. 12, 2016) (eDocket No. 20164-119985-02); *see also In the Matter of the Petition of Minn. Energy Res. Corp. for Approval of a New Base Cost of Gas*, MPUC Docket No. G011/M-15-748, COMPLIANCE FILING -- BASE COST OF GAS UPDATE (Apr. 12, 2016).
933 Ex. 45 at 20 (DeMerritt Rebuttal).
934 Ex. 45 at 20 (DeMerritt Rebuttal).
935 Ex. 401 at 11-12 (Shah Surrebuttal).
936 BASE COST OF GAS UPDATE (Apr. 12, 2016) (eDocket No. 20164-119985-02).
937 Ex. 2, Vol. 1, Interim Rate Petition at 2 (Application).

from the most recent fiscal year and whether the test year should be allowed to start more than 60 days after the filing date.[938]

732. The Department concluded that the 2016 test year is not unreasonably far removed from the most recent calendar year 2014 and did not have a concern with utilities filing more than 60 days in advance of interim rates.[939] The Department, however, cautioned against allowing more than MERC's present filing of 93 days in advance of interim rates.[940]

733. MERC agrees that the 2016 test year is not unreasonably far removed from the most recent calendar year. MERC is not overly concerned with filing a future rate case more than 93 days in advance of interim rates, but requested a few days' leeway in the event September 30 falls on a weekend, such that it becomes necessary to file on the prior Friday and therefore, slightly earlier.[941]

734. The Department agreed with MERC's request.[942]

735. No other party offered testimony on this issue.

736. The Administrative Law Judge finds that the 2016 test year is not unreasonably far removed from the most recent calendar year 2014, and concludes that filing more than 93 days in advance of interim rates should only be allowed in the event September 30 falls on a weekend.

E. Service and Main Extension

737. In its March 31, 1995, Order in Docket No. G999/CI-90-563, the Commission directed each gas utility to address the following six questions in future rate cases relating to the companies' extension rules and policies: (1) Should the free footage or service extension allowance include the majority of all new extensions with only the extremely long extensions requiring a customer contribution-in-aid-of-construction (CIAC)?; (2) How should the Local Distribution Company (LDC) determine the economic feasibility of service extension projects and whether the excess footage charges are collected?; (3) Should the LDC's extension policy be tariffed in number of feet without consideration to varying construction costs among projects or should the allowance be tariffed as a total dollar amount per customer?; (4) Is the LDC's extension charge refund policy appropriate?; (5) Should customers be allowed to run their own service line from the street to the house (or use an independent contractor) if it would be less expensive than having the utility construct the line?; and (6) Should the LDC be required to offer its

[938] NOTICE OF AND ORDER FOR HEARING at 2 (Nov. 30, 2015) (eDocket No. 201511-116011-01).
[939] Ex. 416 at 9-10 (St. Pierre Direct).
[940] Ex. 416 at 10 (St. Pierre Direct).
[941] Ex. 45 at 41-42 (DeMerritt Rebuttal).
[942] Ex. 417 at 3-4 (St. Pierre Surrebuttal).

customers financing for service extension charges? This could be offered as an alternative to paying extension charges in advance of construction.[943]

738. MERC provided responses to all of the questions contained in the Commission's order in Docket No. G999/CI-90-563 in Direct Testimony.[944]

739. MERC conducted the required audit of its main and service extensions to determine whether its extension tariff had been correctly and consistently applied since its last rate case. The result of this review showed that 100 percent of the service lines reviewed met the extension guidelines, and the applicable excess footage fee was properly charged and collected.[945]

740. MERC proposed to continue its currently-approved 75-foot allowance for each stand-alone service extension and its feasibility model for other residential and all commercial and industrial extensions.

741. The Department concluded that MERC's service line extension polices are reasonable and should be approved.[946]

742. No other party offered testimony on this issue.

743. The Administrative Law Judge finds that MERC's service and main extension policies, footage allowance, and feasibility model are reasonable and that MERC demonstrated compliance with its applicable policies.

F. Winter Construction Charges

744. MERC submitted information to address the Commission's requirement in Docket No. G007,011/M-07-1188, that MERC demonstrate that no Winter Construction Charges were being assessed to customers outside the tariffed Winter Construction Charges period (December 1 through April 1), and that no Winter Construction Charges incurred by the Company from any contractors were assessed to ratepayers outside the tariffed Winter Construction Charges period.[947]

745. MERC's review found no winter charge invoices for work done outside the tariffed Winter Construction Charges period and did not request any winter construction charges outside of the tariffed Winter Construction Charge period.[948]

746. No other party filed testimony on this issue.

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[943] *In the Matter of an Inquiry into Competition Between Gas Utils. in Minn.*, MPUC Docket No. G999/CI-90-563, ORDER TERMINATING INVESTIGATION AND CLOSING DOCKET at 6-7 (Mar. 31, 1995).
[944] Ex. 13 at 17-22 (Kult Direct).
[945] Ex. 13 at 23, Schedule DGK-2 (Kult Direct).
[946] Ex. 405 at 29 (Peirce Direct).
[947] Ex. 13 at 28 (Kult Direct).
[948] Ex. 13 at 28-29, DGK-5 (Kult Direct).

747. The Administrative Law Judge finds that no adjustment is necessary relative to MERC's winter construction charges and that MERC demonstrated compliance with its winter construction charge tariffs.

G. Farm Tap Safety Inspection Program

748. In Docket No. G011/M-91-989, the Commission required MERC to file in each general rate case a five-year report on the cumulative results of the Farm Tap Safety Inspection Program and any recommendations for future improvements. MERC is in year three of a five-year (2013-2017) farm tap inspection plan.[949]

749. MERC concluded that its Farm Tap Safety Inspection Program continues to be an effective way to discover and repair leaks in farm tap customers' lines.[950]

750. No other party filed testimony on this issue.

751. The Administrative Law Judge finds that the Commission should approve MERC's five-year Farm Tap Safety Inspection Program report and the proposed continuation of the farm tap program.

H. Purchased Gas Adjustment Consolidation (MERC-Albert Lea)

752. On September 30, 2013, MERC and IPL entered into an Asset Purchase and Sale Agreement for the sale of IPL's Minnesota natural gas distribution system and assets, and transfer of service rights and obligations in Minnesota. As discussed above, the Commission approved the transaction on December 8, 2014. In its order, the Commission required that MERC transfer IPL's natural gas customers to MERC's tariffs upon completion of the transaction, but continue to bill transitioned IPL customers for the customer charge and purchased gas adjustment allowed under IPL's tariff structure until MERC's next rate case.[951]

753. In compliance with the Commission's order, MERC proposed to begin charging the former IPL customers MERC's demand and commodity cost of gas through consolidation of the MERC-Albert Lea PGA with the MERC-NNG PGA and that the consolidation be implemented on July 1, 2017, following implementation of final rates.[952]

754. The Department found MERC's proposed consolidation consistent with the methodology MERC used to consolidate the PGA's of its PNG and NMU operating divisions in its 2010 rate case, Docket No. G007,011/GR-10-977.[953]

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[949] Ex. 13 at 30 (Kult Direct).
[950] Ex. 13 at 31-32 (Kult Direct).
[951] *In the Matter of a Request for the Approval of the Asset Purchase and Sale Agreement Between Interstate Power and Light Co. and Minn. Energy Res. Corp.*, MPUC Docket No. G-001,011/PA-14-107, ORDER APPROVING SALE SUBJECT TO CONDITIONS at 6 (Dec. 8, 2014).
[952] Ex. 33 at 9-11 (Quick Direct); Ex. 37 at 39-40 (Lee Direct).
[953] Ex. 405 at 25-26 (Peirce Direct).

755. The Department generally agreed with MERC's proposal to implement the consolidation on July 1, 2017, but deferred to the Commission as to whether consolidation should be deferred an additional year to provide former IPL customers time to adjust to the rate changes.[954]

756. MERC agreed that its proposal is consistent with the previously-approved methodology for PGA consolidation, but continues to believe that consolidation on July 1, 2017 is appropriate. MERC incurs administrative expense from maintaining a separate Albert Lea PGA and continuation of a separate PGA for an additional year will only result in additional costs incurred. Given the minimum rate impact of PGA consolidation, MERC does not agree that further delay is justified.[955]

757. No other party offered testimony on this issue.

758. The Administrative Law Judge finds that MERC's proposed consolidation of its MERC-NNG and MERC Albert Lea PGAs is reasonable and should be implemented on July 1, 2017, following implementation of final rates.

I. Joint Service Rates

759. Joint service allows an interruptible customer, either system sales or transportation, to designate a portion of its interruptible service as firm service.

760. In MERC's last rate case, Docket No. G011/GR-13-617, issues were raised related to the concern that MERC's joint service customers may be subsidized by MERC's general sales customers. To address these concerns, MERC proposed to charge Joint Service customers the Firm Demand cost per therm rate currently charged to General Service customers for the firm portion of their joint service.[956]

761. The Department determined that MERC addressed the concerns raised in its last rate case and recommended approval of MERC's joint service rates.[957]

762. No other party offered testimony on this issue.

763. The Administrative Law Judge finds that MERC's joint service rates are reasonable and should be approved.

[954] Ex. 405 at 25-26 (Peirce Direct).
[955] Ex. 39 at 29-30 (Lee Rebuttal).
[956] Ex. 37 at 32-33 (Lee Direct).
[957] Ex. 405 at 26-27 (Peirce Direct).

J. Increase to Curtailment Penalty

764. MERC proposed to revise its tariff to increase the curtailment penalty from $20 per dekatherm to $50 per dekatherm. MERC proposed to increase its curtailment penalty to encourage customers to comply with curtailment requests and minimize unauthorized gas usage, in accordance with Order Point 5 of the Commission's August 24, 2015, Order Accepting Gas Utilities' Annual Automatic Adjustment Reports and 2013-2014 True-Up Proposals and Setting Further Requirements in Docket No. G999/AA-14-580.[958]

765. The Department noted that MERC's proposed tariff updated the tariff sheets to reflect the increase in the curtailment penalty, but did not update the curtailment penalty in all of the applicable service agreements. In response to Department Information Request No. 317, MERC submitted revised service agreements to reflect the penalty increase. Based on those updates, the Department concluded that MERC had complied with the Commission's August 24, 2015 Order and the Department recommended approval.[959]

766. No other party offered testimony on this issue.

767. The Administrative Law Judge finds that MERC's increase to the curtailment penalty from $20 per dekatherm to $50 per dekatherm is consistent with the Commission's August 24, 2015 Order and should be approved.

Based on these Findings of Fact, the Administrative Law Judge makes the following:

CONCLUSIONS OF LAW

1. The Minnesota Public Utilities Commission and the Administrative Law Judge have jurisdiction over the subject matter of this proceeding pursuant to Minn. Stat. § 14.50 and Chapter 216B (2016).

2. The parties and the public received proper and timely notice of the hearings in this matter.

3. Every rate set by the Commission shall be just and reasonable. Rates shall not be unreasonably preferential, unreasonably prejudicial or discriminatory, but shall be sufficient, equitable and consistent in application to a class of consumers. To the maximum reasonable extent, the Commission shall set rates to encourage energy conservation and renewable energy use and to further the goals of Minn. Stat. §§ 216B.164, .241, 216C.05 (2016).[960]

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[958] Ex. 37 at 52 (Lee Direct).
[959] Ex. 405 at 30 (Peirce Direct).
[960] Minn. Stat. § 216B.03.

4. The burden of proof is on the public utility to show that a rate change is just and reasonable.[961]

5. Rates set in accordance with this Report would be just and reasonable.

6. Any Findings of Fact more properly designated as Conclusions are hereby adopted as such.

Based on the foregoing Findings of Fact and Conclusions of Law, the Administrative Law Judge makes the following:

RECOMMENDATION

IT IS RECOMMENDED that the Minnesota Public Utilities Commission order that:

1. MERC is entitled to increase its gross annual revenues in the manner and in the amount consistent with the Findings of Fact and Conclusions of Law of this Report.

2. The concepts set forth in these Findings of Fact and Conclusions of Law should govern the mathematical and computational aspects of the Findings and Conclusions. Any computations in the Report that are in conflict with the conclusions of this Report should be adjusted so as to conform to the conclusions of the Report.

Dated: August 19, 2016

Jeanne Cochran

JEANNE M. COCHRAN
Administrative Law Judge

[961] Minn. Stat. § 216B.16, subd. 4 (2016).

NOTICE

Notice is hereby given that exceptions to this Report, if any, by any party adversely affected must be filed under the time frames established in the Commission's rules of practice and procedure, Minn. R. 7829.2700, .3100 (2015), unless otherwise directed by the Commission. Exceptions should be specific and stated and numbered separately. Oral argument before a majority of the Commission will be permitted pursuant to Minn. R. 7829.2700, subp. 3. The Commission will make the final determination of the matter after the expiration of the period for filing exceptions, or after oral argument, if an oral argument is held.

The Commission may, at its own discretion, accept, modify, or reject the Administrative Law Judge's recommendations. The recommendations of the Administrative Law Judge have no legal effect unless expressly adopted by the Commission as its final order.

OAH 68-2500-32993
MPUC Docket No. G011/GR-15-736

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota	**ATTACHMENT A** **SUMMARY OF PUBLIC COMMENTS**

Pursuant to Minn. R. 7829.1100 (2015), the Administrative Law Judge conducted public hearings on March 28, March 29, and March 30, 2016. The public hearings were held to elicit public comment regarding the proposed rate increase by MERC.

The first public hearing on MERC's proposed rate increase was held on March 28, 2016 at the Cloquet Chamber of Commerce in Cloquet, Minnesota. The second public hearing was held on March 29, 2016 at Rochester City Hall in Rochester, Minnesota. The third public hearing was held on March 29, 2016 at the Albert Lea City Offices in Albert Lea, Minnesota, and a fourth Public hearing was held on March 30, 2016 at Dakota County Technical College in Rosemount, Minnesota.

The public was also provided an opportunity to submit written comments, either electronically or by U.S. mail, until April 15, 2016. Written comments were filed in the Commission's eDockets system.

A summary of the comments received at the public hearings and in writing follows below:

I. Summary Comments at the Public Hearings

<u>Cloquet, Minnesota Public Hearing – Cloquet Chamber of Commerce</u>

At the public hearing in Cloquet, Minnesota, nine (9) members of the public attended and six (6) offered comments for the hearing record.

Susan Pedersen, lives in Moose Lake and owns a farm between Pine City and Mora where she receives farm tap service from the Company. Ms. Pederson is opposed to the proposed rate increases and expressed concern over how MERC implements its charges for farm tap customers. In her view, MERC has been overcharging farm tap customers and she would like to see MERC charge only for the actual Ccfs that are delivered to the meter. She also expressed concern about MERC's billing practices and customer service.[962]

David Bartrick questioned why rates are increasing when natural gas is at its lowest price in 17 years. He expressed concern that, as the price of natural gas has fallen, the price charged by MERC has stayed the same. In his view, a rate increase is not justified.[963]

David Johnson is a ratepayer from Cloquet who owns several apartment buildings. He expressed disappointment that all of his rental properties must be billed and paid for individually and cannot be consolidated on one bill. Mr. Johnson also raised concern about the difficulty he has reading his billing statements due to the small font. In addition, Mr. Johnson believes that the notice of the public hearing was inadequate.[964]

Karen Durfee opposed the rate hike. She indicated that natural gas prices have been decreasing and a rate increase is unwarranted. In her view, the gas delivery system is adequate and any improvements should be minimal.[965]

Lorna Hanes opposed the rate increase and noted that the money would be better spent on alternative energy solutions.[966]

Debra Topping expressed concern that low-income members of the community could not afford the rate increase. Ms. Topping explained that her daughter, who lives in Cloquet, has a limited budget and cannot afford a rate increase.[967]

Rochester, Minnesota Public hearing – Rochester City Hall

At the public hearing in Rochester, Minnesota, six (6) members of the public attended and two (2) offered comments for the hearing record.

Thomas Deboer, a ratepayer from Rochester, described the community's heavy reliance on natural gas and noted that demand for natural gas is increasing due to the retirement of coal-fired power plants. In his view, inability to meet demand would be detrimental to the community and it is imperative that MERC invest in infrastructure and maintenance necessary to meet future demand.[968] Mr. Deboer supported MERC's request for a rate increase.[969]

Anna Richey, a resident of Rochester and vice chair of the Rochester Energy Commission, raised concerns about the disproportionate effects of the rate increase on

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[962] Cloquet Public Hearing Transcript at 21-31 (Mar. 28, 2016).
[963] *Id.* at 31-38.
[964] *Id.* at 38-46.
[965] *Id.* at 46-49.
[966] *Id.* at 49-51.
[967] *Id.* at 51-56.
[968] Rochester Public Hearing Transcript at 21-32 (Mar. 29, 2016).
[969] *Id.*

low and fixed income residents. Her belief is that MERC can find alternative ways of financing the improvements.[970]

Albert Lea, Minnesota Public Hearing – Albert Lea City Offices

At the public hearing in Albert Lea, Minnesota, six (6) members of the public attended and four (4) offered testimony for the hearing record.

Alan Bakken, an agricultural business owner from Albert Lea Township, expressed concern that the proposed rate increases will negatively affect the already struggling agricultural community. His business uses natural gas to dry crops and he estimates that his cost will increase by 27 percent.[971]

Dave McKinney, a resident from Albert Lea, expressed concern that the rate increase is too high. In his view, MERC and its parent company WEC Energy Group, have increased their net income in recent years and need to provide more information as to where the money from the rate increase will be spent.[972]

Harold Kamrath, a resident from Albert Lea, opposed any rate increase. His concern is that the increase comes at a time when residents have been faced with tax increases from the city and county while wages and Social Security payments have stayed the same.[973]

Ryan Nolander, the executive director of the Economic Development Agency in Albert Lea, explained that MERC's proposal would increase rates for small commercial industrial customers in the former IPL service area by 47 percent, and large commercial industrial customers in the former IPL service area by over 23 percent. In his view, the proposed rate increases will hurt existing businesses in Albert Lea, which was formerly served by IPL, and will make it difficult to attract new businesses to the area.[974]

Rosemount, Minnesota Public Hearing – Dakota County Technical College

No members of the public were in attendance at the public hearing in Rosemount.

II. Summary of the Written Comments

In addition to the testimony at the hearings, the Commission received over 40 written comments by electronic or first class mail before the close of the comment period on April 15, 2016.

[970] *Id.* at 32-35.
[971] Albert Lea Public Hearing Transcript at 20-23 (Mar. 29, 2016).
[972] *Id.* at 23-26.
[973] *Id.* at 26-30.
[974] *Id.* at 30-32.

John Roemer expressed concern that MERC has not provided enough detail on the rate increase. He recommended that any increase be rejected until a better explanation is provided.[975]

Tony Cy asserted that the proposed rate increases are excessive and unjustified. He stated that the Company's mailing, entitled "Important Information About Your Rates," did not provide specific reasons for the proposed rate increases. He expressed concern for Minnesota families who are struggling to meet utility costs. He requested that the rate increases be denied until MERC can provide detailed numbers justifying the increases.[976]

David Roden agreed with Tony Cy that the Company's mailing failed to explain the specific reasons for the proposed rate increases, and requested that any rate increase be denied until MERC can prove the need for the increase.[977]

Lyne Roginski opposed the rate increase. She noted that she did not receive any increase in her Social Security income this year, and believes that MERC cannot justify an increase based on inflation.[978]

Steve Kay suggested that the rate increase should be denied. He believes that there has not been any inflation to justify the increased rates and also noted that natural gas prices have not increased.[979]

Zekaleah Delz asserted that an increase will be hard on people that are retired and living on a fixed income. He also noted that there has been no inflation to justify an increase and stated any increased costs can be written off as "business expenses."[980]

Dick Hegal asked that the Commission deny MERC's request. In his view, there should be no rate increase based on inflation because there was no increase for Social Security recipients.[981]

Rick Bichel shared his concern that wages are not increasing and such an excessive increase will adversely affect MERC's customers.[982]

Tom Smith requested that the increase be rejected. He believes the increase is unjustified due to the fact that the price of natural gas has fallen.[983]

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975 Comment by John Roemer (Jan. 12, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
976 Comment by Tony Cy (Jan. 14, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
977 Comment by David Roden (Jan. 28, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
978 Comment by Lynne Roginski (Feb. 1, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
979 Comment by Steve Kay (Feb. 4, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
980 Comment by Zekaleah Delz (Feb. 8, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
981 Comment by Dick Hegal (Feb. 18, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
982 Comment by Rick Bichel (Feb. 21, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
983 Comment by Tom Smith (Feb. 22, 2016) (SpeakUp) (eDocket No. 20164-120493-01).

Richard Horihan commented that the increase should be denied because the distribution and customer charges are increasing at unsustainable rates.[984]

Brad Becker is not in favor of another rate increase. He believes that the addition of new customers and falling price of natural gas should allow MERC to operate sustainably without a rate increase. He noted also that his wife has not had a raise in the last six years, and suggested that MERC do more to operate within its existing budget as it customers have had to do.[985]

Aaron Thun also expressed concern about MERC's request for another rate increase and asked the Commission to deny the request. In his view, MERC is asking for a much higher increase than it needs. He believes with the drop in natural gas prices, the rates should be decreased.[986]

Barry Reburn urged the Commission to deny the request, citing the drop in natural gas prices over the last three years.[987]

Alan Anderson suggested that the request be denied. He explained that with natural gas prices falling, an increase would be unjustified. He noted that he is a retiree living on Social Security, and did not receive any increase in his Social Security income this year. He suggested that the Commission not grant any increase for at least a couple years.[988]

Robert Nyman asked that the Commission deny the request. His concern is that the cost of living has been rising while government pensions and Social Security have stayed the same. In his view, this rate hike is unjustified and will have a great impact on fixed income residents.[989]

Gary Skelton urged the commission to deny MERC's request. In his view, there should be no rate increase based on inflation because there was no increase for Social Security.[990]

Ken Witte argued that more information should be supplied from MERC to explain why the rate increase is deserved. In his view, MERC should be experiencing record profits at current rates and does not need to increase rates.[991]

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[984] Comment by Richard Horihan (Feb. 22, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[985] Comment by Brad Becker (Feb. 25, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[986] Comment by Aaron Thun (Feb. 25, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[987] Comment by Barry Reburn (Feb. 26, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[988] Comment by Alan Anderson (Feb. 29, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[989] Comment by Robert Nyman (Mar. 9, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[990] Comment by Gary Skelton (Mar. 9, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[991] Comment by Ken Witte (Mar. 10, 2016) (SpeakUp) (eDocket No. 20164-120493-01).

Dave Herbeck expressed concern that consumers should not be seeing a rate increase when natural gas is at an all-time low. He suggested that customers should be given a rate decrease.[992]

Harry Schuur agreed that customers should be receiving a rate decrease rather than an increase.[993]

Robert Langen believes that MERC should make cutbacks to its costs rather than increasing its rates. He noted that senior citizens have not had an increase in Social Security payments for a number of years.[994]

Timothy Matson expressed concern that the brochure sent out by MERC did not explain the reasoning behind the increase. In his view, the increase is going to hurt many residents who live on a fixed income.[995]

Cole Pestorious urged the Commission to deny the request and explained that the increase will greatly impact producers in the agriculture industry. He asserted that natural gas prices are similar to what they were in the 1990's and argued a rate increase is unjustified.[996]

Kris Pierce suggested that the brochures sent out by MERC were very misleading. She believes that the increase would be difficult for residents and businesses to absorb and questioned whether the capital expenditures by MERC are really necessary.[997]

Pamela Sander, a small business owner in Albert Lea, is not opposed to some increase but stated that the proposed increase for customers in the Albert Lea area is too large. She explained that the proposed rate changes will increase her business costs dramatically.[998]

Chad Vogt requested that the proposed rate increase be denied. In his view, the increase will place a large burden on families and small businesses, which is unjustified due to the price of natural gas being low.[999]

Jeff Woodside, a ratepayer and business owner, explained that the increase would impact the ability of his business to remain competitive in the marketplace because his company is a high volume user of natural gas. He believes the proposed rate increase will hinder his ability to provide higher wages and better benefits to his employees. He also noted that the rate increases will increase the cost of his products to consumers.[1000]

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[992] Comment by Dave Herbeck (Mar. 10, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[993] Comment by Harry Schuur (Mar. 14, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[994] Comment by Robert Langen (Mar. 17, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[995] Comment by Timothy Matson (Mar. 29, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[996] Comment by Cole Pestorious (Mar. 30, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[997] Comment by Kris Pierce (Apr. 11, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[998] Comment by Pamela Sander (Apr. 12, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[999] Comment by Chad Vogt (Apr. 12, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[1000] Comment by Jeff Woodside (Apr. 13, 2016) (SpeakUp) (eDocket No. 20164-120493-01).

Edward Zachary argued that the rate increase should be denied. He believes that the increased revenue is unnecessary, and that MERC should be able to continue operating without increasing rates.[1001]

Charlotte McCann asked that the request for a rate increase be denied. In her view, MERC is passing along unnecessary costs to the consumers. She believes that MERC should bear the burden of any additional costs.[1002]

Steve Wilson recommended that the commission deny MERC's request for increased rates. He noted that the proposed rate increase would adversely affect Zinpro Corporation, where he works. He noted that MERC raised its rates recently and questioned whether another rate increase is really necessary. He noted that if this proposed rate increase is approved, the operating costs for this facility will increase by over $40,000 annually in just the two years. He is concerned that the rate increase is excessive, unjustified, and will have a negative impact on his business.[1003]

Marco Polo recommended that with natural gas prices being so low, MERC should be decreasing rates. He also raised a concern that the bills provided by MERC are complicated and confusing, particularly the fees added to the base cost of service.[1004]

Paul Weber, a farmer and ratepayer asked that the rate increase be denied. He stated that MERC has poor customer service. He noted that he has had trouble with meter reading. In addition, MERC has not been responsive to his request to have a larger meter and regulator installed so that he can operate his grain dryer with natural gas.[1005]

Roger Swanson requested that MERC justify the rate increase. According to him, MERC's costs have gone down and this increase is unwarranted.[1006]

Dustin Trail opposed the increase. In his view, natural gas is 6.5 times cheaper than it was in 2008 and the increase cannot be justified. He requested that the rates stay the same or be decreased.[1007]

[1001] Comment by Edward Zachary (Apr. 13, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[1002] Comment by Charlotte McCann (Apr. 14, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[1003] Comment by Steve Wilson (Apr. 14, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[1004] Comment by Marco Polo (Apr. 14, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[1005] Comment by Paul Weber (Apr. 14, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[1006] Comment by Roger Swanson (Apr. 15, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[1007] Comment by Dustin Trail (Apr. 15, 2016) (SpeakUp) (eDocket No. 20164-120493-01).

David Broman suggested that the rates should not be increased while natural gas prices are decreasing.[1008]

Mark Roalson asserted that there is no justification for a rate increase by MERC and that any increase will have a great impact on fixed income residents.[1009]

D. Marinella suggested that Social Security recipients have not received a cost of living increase, and MERC is not justified in raising rates.[1010]

James Fredrickson opposed the increase on the basis that MERC's prices are already too high. In his view, this increase is unjustified and will have a detrimental impact on the public.[1011]

Richard Horihan expressed a concern that the notice he received from MERC was late and did not separate customer charges from per therm distribution charges. He believes the rate increases are excessive and urged the commission to deny the request.[1012]

Ward Are explained that the price of natural gas has fallen while the supply has increased. As a result, he believes the rate increase is unjustified and asked that the Commission deny the request.[1013]

Gloria Hill opposed the increase. She believes that the increase will have a negative impact on senior citizens who have fixed incomes. She noted that that Social Security recipients have not seen an increase in their income, and many senior citizens already have a difficult time paying their bills. She stated that some even go without medication as a result. She believes that a rate increase based on inflation is unjustified.[1014]

Rose Ward requested that the Commission deny the rate increase. In her view, people are already paying too much for their utility bills.[1015]

David and Mary Styczinski stated that a rate increase should not be approved at a time when natural gas prices are at a historic low. They suggested that MERC should find ways to cut costs instead of increasing the rates.[1016]

Alan Lindeman, who lives in Albert Lea, urged the Commission to deny the request. As a Social Security recipient, he did not receive a raise but his cost of living has been rising. He noted that he has taken a number of steps to reduce his gas usage,

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[1008] Comment by David Broman (Mar. 26, 2016) (eDocket No. 20164-120493-01).
[1009] Comment by Mark Roalson (Mar. 15, 2016) (eDocket No. 20164-120493-01).
[1010] Comment by D. Marinella (Jan. 29, 2016) (eDocket No. 20164-120493-01).
[1011] Comment by James Fredrickson (Feb. 9, 2016) (eDocket No. 20164-120493-01).
[1012] Comment by Richard Horihan (Feb. 22, 2016) (eDocket No. 20164-120493-01).
[1013] Comment by Ward Are (Feb. 22, 2016) (eDocket No. 20164-120493-01).
[1014] Comment by Gloria Hill (Feb. 17, 2016) (eDocket No. 20164-120493-01).
[1015] Comment by Rose Ward (Mar. 4, 2016) (eDocket No. 20164-120493-01).
[1016] Comment by David and Mary Styczinski (Mar. 1, 2016) (eDocket No. 20164-120493-01).

such as adding more insulation and installing new windows. He believes that a rate increase is unwarranted.[1017]

[1017] Comment by Alan Lindeman (Feb. 27, 2016) (eDocket No. 20164-120493-01).

MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

PO Box 64620
Saint Paul, MN 55164-0620
mn.gov/oah

PH (651) 361-7900
TTY (651) 361-7878
FAX (651) 539-0310

August 19, 2016

See Attached Service List

Re: In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota

OAH 68-2500-32993
MPUC G-011/GR-15-736

To All Persons on the Attached Service List:

Enclosed and served upon you is the Administrative Law Judge's **FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION** in the above-entitled matter.

If you have any questions, please contact my legal assistant Denyse Johnson at (651) 361-7888 or denyse.johnson@state.mn.us, or facsimile at (651) 539-0310.

Sincerely,

Jeanne Cochran

JEANNE M. COCHRAN
Administrative Law Judge

JMC:dj
Enclosure
cc: Docket Coordinator

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
PO BOX 64620
600 NORTH ROBERT STREET
ST. PAUL, MINNESOTA 55164

CERTIFICATE OF SERVICE

In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota	OAH Docket No.: 68-2500-32993 MPUC G-011/GR-15-736

Denyse Johnson, certifies that on August 19, 2016 she served the true and correct **FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION** by eService, and U.S. Mail, (in the manner indicated below) to the following individuals:

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes
Elizabeth	Brama	ebrama@briggs.com	Briggs and Morgan	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No
Jeanne	Cochran	Jeanne.Cochran@state.mn.us	Office of Administrative Hearings	P.O. Box 64620 St. Paul, MN 55164-0620	Electronic Service	Yes
Ian	Dobson	ian.dobson@ag.state.mn.us	Office of the Attorney General-RUD	Antitrust and Utilities Division 445 Minnesota Street, 1400 BRM Tower St. Paul, MN 55101	Electronic Service	Yes
Darcy	Fabrizius	Darcy.fabrizius@constellation.com	Constellation Energy	N21 W23340 Ridgeview Pkwy Waukesha, WI 53188	Electronic Service	No
Emma	Fazio	emma.fazio@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	Yes
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department	85 7th Place E	Electronic	Yes

			of Commerce	Ste 500 Saint Paul, MN 551012198	Service	
Robert	Harding	robert.harding@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 55101	Electronic Service	Yes
Linda	Jensen	linda.s.jensen@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota Street St. Paul, MN 551012134	Electronic Service	Yes
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No
Amber	Lee	ASLee@minnesotaenergyresources.com	Minnesota Energy Resources Corporation	2665 145th St W Rosemount, MN 55068	Electronic Service	No
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes
Peter	Madsen	peter.madsen@ag.state.mn.us	Office of the Attorney General-DOC	Bremer Tower, Suite 1800 445 Minnesota Street St. Paul, Minnesota 55101	Electronic Service	Yes
Joseph	Meyer	joseph.meyer@ag.state.mn.us	Office of the Attorney General-RUD	Bremer Tower, Suite 1400 445 Minnesota Street St Paul, MN 55101-2131	Electronic Service	Yes
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	Yes
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	Ste 122 9100 W Bloomington Frwy Bloomington, MN 55431	Electronic Service	Yes
Kristin	Stastny	kstastny@briggs.com	Briggs and Morgan, P.A.	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Petition of Southwest Gas Corporation to establish a regulatory asset to accumulate the return on investment, incremental depreciation, and property taxes related to the accelerated replacement of early vintage plastic pipe in Southern Nevada.	Docket No. 12-02019
Application of Southwest Gas Corporation for authority to increase its rates and charges for natural gas service for all classes of customers in Southern and Northern Nevada.	Docket No. 12-04005

At a general session of the Public Utilities Commission of Nevada, held at its offices on March 14, 2013.

PRESENT: Chairman Alaina Burtenshaw
Commissioner Rebecca D. Wagner
Commissioner David Noble
Assistant Commission Secretary Breanne Potter

SECOND MODIFIED FINAL ORDER

The Public Utilities Commission of Nevada ("Commission") makes the following findings of fact and conclusions of law:

I. INTRODUCTION

Southwest Gas Corporation ("SWG") filed a Petition with the Commission, designated as Docket No. 12-02019, to establish a regulatory asset to accumulate the return on investment, incremental depreciation, and property taxes related to the accelerated replacement of early vintage plastic pipe in Southern Nevada.

SWG also filed an Application with the Commission, designated as Docket No. 12-04005, for authority to increase its rates and charges for natural gas service for all classes of customers in southern and northern Nevada.

II. SUMMARY

The Commission denies SWG's Petition and grants SWG's Application as modified by this Order. The Commission grants a return on equity ("ROE") of 9.30 percent in the Northern Nevada Division ("NND") and 10.0 percent in the Southern Nevada Division ("SND"), which

Staff's Position

73. Staff did not address this issue in its direct testimony.

Commission Discussion and Findings

74. NAC 704.222 provides that changes in rates authorized by variable interest securities are effective at the same time as a change in the rates resulting from a general rate case. The Commission approves SWG's request to modify its VIER mechanism. In the 2011 annual rate proceeding to reset the VIER rates, SWG testified that the variable interest debt in the VIER mechanism saved ratepayers $15.8 million from September 2004 to April 2011 compared to the fixed rate alternatives and no party challenged this testimony. (Docket No. 11-06003, Exhibit 1 at 5.) These savings demonstrate that the VIER mechanism has provided a net benefit to ratepayers since its inclusion in rates. Based on these past savings, the Commission finds that the addition of the $50 million 2009 Clark County Series A IDRBs to the VIER mechanism is reasonable.

D. RETURN ON EQUITY ("ROE")

SWG's Position

i. Hearing (September 10-14, 2012)

75. SWG requests that the Commission authorize an increase from its current 10.15 percent ROE to 10.65 percent. (Exhibit 21 at 22; Exhibit 24 at 5, 53.) SWG states that its cost of equity is currently in the range of 10 to 10.75 percent, and that its proposed ROE of 10.65 percent is conservative, reasonable and appropriate. (Exhibit 24 at 5, 7, 53; Exhibit 21 at 22.) SWG states that the proposed ROE is based on quantitative and qualitative analyses performed

by SWG, and accounts for the regulatory and capital environment in which SWG operates.[4] (Exhibit 24 at 5-7, 53.)

76. Because the ROE is a market-based concept, SWG also utilized a proxy group in estimating the ROE. (*Id.* at 10.) SWG selected ten comparable companies to include in the proxy group ("Proxy Group"), a number sufficiently large enough to be representative of SWG's ROE, but excluded SWG from the analysis to avoid circular logic.[5] (*Id.* at 12-13.)

77. The following table summarizes the range of ROEs calculated by SWG after applying the following common estimation methodologies: constant and multi-stage discounted cash flow ("DCF"), capital asset pricing model ("CAPM"), and bond yield plus risk premium. (*Id.* at 5.)

Methodology	Suggested Range
Constant DCF	9.12% to 11.04%
Multi-Stage DCF	9.53% to 11.13%
CAPM	10.00% to 11.00%
Bond Yield + Risk Premium	10.18%
Recommended Range	**10.00% to 10.75%**

(*Id.* at 6-7, 24, 31.)

78. SWG's DCF analyses[6] included the retention growth method, which is a widely used method for estimating long-term growth. (Exhibit 24 at 19.) SWG incorporated the forecasted earnings growth rates published by three well-known analysts.[7] (*Id.* at 17-18.) SWG

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[4] According to SWG, given its "BBB+" credit rating and Value Line common stock safety ranking of 3.0, it is a riskier utility than its proxy companies which have a weighted "A-" credit rating and a weighted 1.7 common stock safety ranking. (Exhibit 21 at 19-20, Att. TKW-2 at 1, and Att. TKW-3.)

[5] SWG's criteria for selecting utilities to include in the Proxy Group consisted of those companies that: (a) are publicly traded; (b) are classified by Value Line (an independent investment research and financial publishing firm) as "Natural Gas" or "Natural Gas Utilities;" (c) consistently pay quarterly cash dividends; (d) are covered by at least two utility industry equity analysts; (e) have investment grade senior bond and/or corporate credit ratings from S&P; (f) have regulated natural gas utility operations which provide at least 60 percent of net operating income; and (g) are not a party to a merger or other significant transaction. (Exhibit 24 at 10, 12.)

[6] In the DCF analyses, SWG used stock data ending February 29, 2012. (*Id.* at 16.)

[7] Specifically, the consensus long-term earnings growth estimates published by Zacks, First Call, and Value Line. (*Id.* at 19.)

estimated the third-stage dividend growth rate at 5.79 percent in the multiple-stage DCF. (*Id.* at 23.) This 5.79 percent consists of the 3.24 percent real growth in the gross domestic product ("GDP") for the period 1926 to 2011,[8] and the inflation rate of 2.47 percent which is the spread between yields on long-term nominal U.S. Treasury securities and long-term Treasury Inflation Protected Securities. (*Id.*) SWG notes that the second-stage dividend growth rate is a transitional rate developed using the first and third-stage rates. (*Id.* at 23-24.)

79. SWG's "high" DCF ROE estimates were calculated using the maximum earnings growth rate reported for each company in the Proxy Group. (*Id.* at 20.) SWG's "low" ROE estimates were calculated with a similar methodology, but using the minimum reported earnings growth rate. (*Id.*)

80. SWG's CAPM methodology is a risk premium model, which provides that the ROE is equal to the risk-free rate of return plus the beta (market risk premium), with beta representing the relative volatility of the utility in comparison to the market as a whole. (*Id.* at 25-26.) The risk-free rate of return is represented by the interest rate on long-term U.S. Treasury securities. (*Id.* at 26, Att. RBH-6.) SWG's analysis to estimate the risk-free rate utilized two 30-year U.S. Treasury Bond yields, including the 30-day average yield (3.09 percent) and the near–term projected yield (3.50 percent). (*Id.* at 27.) SWG asserts that using these forward-looking estimated market risk premiums is necessary because the Federal Reserve policy of maintaining low long-term interest rates together with investors seeking low risk securities have caused historical market risk premiums to remain below pre-financial crisis levels. (*Id.* at 26-27.) SWG estimated the forward-looking market risk premiums at 8.62 percent, 9.13 percent, and 10.43 percent, while the historic market risk premium was only 6.7 percent. (*Id.* at 27-29, Att. RBH-4.)

[8]Bureau of Economic Analysis, February 29, 2012 update. (*Id.* at 23.)

81. SWG used three beta approaches in its CAPM analysis, including Bloomberg (calculated using two years of data), Value Line (calculated using five years of data), and one that SWG calculated using more recent information. (*Id.* at 29.) The three betas are 69.5 percent (Value Line), 79.5 percent (Bloomberg), and 82.9 percent (SWG). (*Id.* at Att. RBH-6.) The Value Line and SWG betas showed an increased correlation between the Proxy Group and the market. (*Id.* at 29.)

82. SWG states that the bond yield plus risk premium method is equal to the difference between the authorized ROE and the then-prevailing 30-year U.S. Treasury Bond yield. (*Id.* at 32.) SWG developed the risk premium using a regression analysis of rate case decisions issued in 1980 through January 2012. (*Id.* at 32-33.) For the risk-free rate of return SWG used the near-term forecasted U.S. Treasury 30-year bond yield (3.50 percent). (*Id.* at 34.)

83. SWG asserts that equity investors consider whether SWG is materially more risky than other available investments by examining the rate mechanisms that are available to SWG to reduce risk in comparison to other companies—in this instance, the Proxy Group. (Tr. at 155-58.) All companies in the Proxy Group have some form of decoupling mechanism in place. (Exhibit 24 at 47, Att. RBH-8.) SWG performed analyses to determine whether equity investors viewed SWG as less risky than the companies in the Proxy Group subsequent to its implementation of revenue decoupling. (*Id.* at 47-50.) The analyses, such as Value Line's equity rankings and earnings predictability indicators and a comparison of SWG's risk beta to the Proxy Group beta, indicate that SWG is not viewed to be less risky than the Proxy Group. (*Id.* at 50.) Thus, SWG asserts that no adjustment to the ROE is warranted due to its current general revenue adjustment ("GRA") mechanism. (*Id.* at 51.)

84. SWG also contends that no adjustment to the requested 10.65 percent ROE will be necessary to reflect authorization of its proposed gas infrastructure replacement mechanism ("GIR"). (*Id.* at 53.) This is because the 2012 American Gas Association ("AGA") study report indicates that all companies in the Proxy Group have some form of infrastructure replacement mechanism in place. (*Id.*)

BCP's Position

85. BCP recommends a ROE of 9.2 percent and an adjustment of 25 basis points downward to reflect the impacts of decoupling. BCP contends that SWG's ROE is overstated and recommends an ROE of 9.2 percent, based on an estimated cost of equity ranging from 8.7 to 9.7 percent. (Exhibit 26 at 3, 5.) BCP acknowledges that this recommendation does not take into consideration SWG's GRA. (*Id.* at 47.) Rather, BCP recommends that a 25 basis point reduction be made to the Commission-approved ROE for the GRA, which would result in an ROE of 8.95; however, BCP states that the final ROE should not fall below 8.70 percent. (*Id.*) BCP asserts that its recommended ROE, with or without an adjustment for the GRA, will provide SWG with sufficient cash flow and earnings to achieve the necessary financial metrics for its current credit ratings. (*Id.* at 70.)

86. BCP argues that current economic conditions fail to support higher utility ROEs. (*Id.* at 7.) Since September 2008, government intervention responding to the financial and economic turmoil has reduced the cost of capital, as evidenced by reduced utility borrowing costs and declining authorized ROEs. (*Id.* at 7-8.) BCP further argues that it is reasonable to expect lower than historical long-term interest rates to continue into the foreseeable near-term. (*Id.* at 11-12.) BCP notes the observed decline in long-term interest rates, which are near six-year lows. (*Id.* at 11.)

87. BCP attributes the continued decline in longer-term interest rates to the U.S. Federal Reserve's monetary policy, beginning in December 2008, to maintain a near-zero federal funds rate (i.e., 0 to 0.25 percent). (*Id.* at 8.) In June 2012, the U.S. Federal Reserve issued a press release expressing its intent to continue this monetary policy through the end of 2014. (*Id.* at 10.) The Federal Reserve refers to slower growth than previously estimated as the basis for extending this date (previously scheduled to terminate in mid-2013). (*Id.*) Specifically, during a June 2012 meeting, the Federal Reserve Bank's Federal Open Market Committee forecasted economic growth to be as follows:

	2012	2013	2014	Long-Run
GDP June Estimate	1.9% - 2.4%	2.2% - 2.8%	3.0% - 3.5%	2.3% - 2.5%
GDP April Estimate	2.4% - 2.9%	2.7% - 3.1%	3.1% - 3.6%	2.3% - 2.6%
Inflation June Estimate	1.2% - 1.7%	1.5% - 2.0%	1.5% - 2.0%	2.0%
Inflation April Estimate	1.9% - 2.0%	1.6% - 2.0%	1.7% - 2.0%	2.0%

(*Id.*)

88. BCP further notes that Moody's, a credit rating agency, issued a general industry report in July 2012 stating that the gas utility industry outlook is stable, which is attributed in part to the low interest rate environment. (*Id.* at 14-15.)

89. BCP developed its recommended ROE using three of the same methodologies used by SWG, including DCF, CAPM, and Bond Yield Plus Risk Premium. (*Id.* at 31.) BCP then applied these methodologies to SWG's Proxy Group. (*Id.* at 32.) The following table summarizes the results of BCP's analyses.

Methodology	Range[9]	Mid-Point
Constant Growth DCF	9.6% to 9.6%	
Two-Stage DCF	8.7% to 9.1%	
DCF	8.7% to 9.4%	9.1%
Risk Premium	9.3% to 9.7%	9.4%

[9] The "range" consists of the average and median values calculated for the comparable Proxy. (Exhibit 26 at Att. DJL-6, DJL-7, and DJL-9.)

CAPM	8.7% to 9.1%	8.9%
BCP Recommendation	**8.7% to 9.7%**	**9.2%**

(*Id.* at 41, 43, 46-47, Att. DJL-6, Att. DJL-7, Att. DJL-9.)

90. BCP states that the DCF methodologies are the best analytical techniques for measuring a utility's cost of common equity. (*Id.* at 31.) BCP asserts that the risk premium and CAPM methodology results must be evaluated with caution because these methodologies are subject to measurement uncertainties, including the time period used to determine the premium. (*Id.* at 42.) Further, these methodologies presume that historical debt/equity risk spreads, measured over many decades, are relevant to the current capital market requirements. (*Id.*)

91. BCP states that its constant growth DCF analysis[10] dividend growth rate was developed using forecasted earnings growth rates from the analysts referenced by SWG.[11] (*Id.* at 38.) BCP asserts that SWG's 4.9 to 6.1 percent growth rate range is both outdated and overstated. (*Id.* at 39.) BCP's analysis results in a range of average and median forecasted growth rates for SWG and its Proxy Group between 3.0 to 5.5 percent. (*Id.*)

92. BCP asserts that SWG's multi-stage DCF analysis is also overstated because the underlying GDP growth rate and inflation rate exceed current forecasted rates. (*Id.* at 71.) Correcting for these errors would result in a multi-stage DCF analysis with results similar to BCP's two-stage DCF analysis. (*Id.* at 72.) For stage one, BCP used Value Line's forecasted dividend growth rate, and for stage two BCP used the Proxy Group average of 5.1 to 5.5 percent long-run earnings growth estimate. (*Id.* at 40.)

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[10] In this analysis, BCP used the stock data for the six-week period ending July 31, 2012. (*Id.* at 36.)
[11] Value Line, Zacks, and First Call. (*Id.* at 38.)

93. BCP's risk premium analysis consisted of comparing authorized ROEs for electric utilities to three different debt security yields[12] for the period 1980 to 2011. (*Id.* at 42-43.)

94. BCP's CAPM analysis used the forecasted 30-year U.S. Treasury Bond yield rate (3.9 percent) as the risk-free rate, rather than the current or 3-month historical average that is generally employed. (*Id.* at 44.) BCP states that using the forecasted 30-year U.S. Treasury bond yield rate recognizes that forecasted yields for the next 36-month period are significantly higher than the current yields (3.9 percent compared to rates approaching 2.5 percent). (*Id.*) BCP used two market risk premiums, the historical risk premium (1926 to 2011) of 5.7 percent and an estimated 7.9 percent, which was derived by replacing the historical government bond yield (1926 to 2011) with the forecasted 3.9 percent rate. (*Id.* at 44-45.)

95. Additionally, BCP employed an empirical CAPM ("ECAPM") technique. (*Id.* at 46.) BCP states that some have argued that the CAPM understates the ROE for a utility with a beta less than 1 and overstates those entities with a beta greater than 1. (*Id.*) BCP used an adjustment factor of 25 percent for the direct assignment of the market risk premium to SWG, with the beta-determined risk premium weighted at 75 percent. (*Id.*)

96. BCP recommends that, if the decoupling process is continued, the Commission should also continue to reduce the ROE by 25 basis points. (*Id.* at 26.) This adjustment recognizes a shifting of business risk from the shareholders to the ratepayers. (*Id.* at 5.) BCP asserts that cost recovery mechanisms, such as balancing accounts and decoupling, stabilize utility cash flow, reduce risk and support creditworthiness. (*Id.* at 16-17.) BCP states that decoupling also reduces the risk of revenue and profit erosion between rate cases. (*Id.* at 17.) BCP notes that two credit rating agencies, Standard & Poor's ("S&P") and Moody's, have

[12] Namely, Moody's Average Public Utility Bond Yield, Baa corporate bond yields, and 30-year U.S. Treasury yields. (*Id.* at 42-43.)

indicated that such non-general rate recovery mechanisms reduce risk. (*Id.* at 18.) S&P's April 2012 credit rating report for SWG identifies steady cash flow and decoupling mechanisms as positive aspects. (Exhibit 26, App. B at 1.) Moody's March 2012 credit rating report for SWG identifies timely recovery of variable cost of service and decoupling as positive aspects. (*Id.* at 4.) Moreover, BCP notes that SWG acknowledged that credit rating agencies view these mechanisms positively. (*Id.* at 23-24.)

Staff's Position

97. Staff recommends the Commission authorize a 9.1 percent ROE. (Exhibit 29 at 1.) Staff states that it calculated a reasonable range of ROEs between 8.7 to 9.5 percent. (*Id.* at 3.) Staff contends its ROE analysis comports with U.S. Supreme Court decisions guiding ROE determination. (*Id.* at 6.) Staff's recommendation incorporates the proposed GIR because more than half of the companies in the Proxy Group already have infrastructure replacement mechanisms. (*Id.* at 35.) Further, Staff's recommendation addresses the issue of potentially "abnormal" low interest rates (e.g., "flight to quality"—investors seeking safe investments amid Europe economic crisis) by giving less weight to the CAPM methodology. (*Id.* at 31.)

98. Staff recommends the Commission consider current economic and market conditions in its determination of the ROE. (*Id.* at 28.) Economic recovery since the "Great Recession" has been slow, and slow economic growth is projected into the future. (*Id.* at 29.) The following table demonstrates this point:

	Historical (1929-2011)	**Forecasted (2010-2035)**
Nominal GDP Growth	6.28%	4.4% - 4.8%
Real GDP Growth	3.24%	2.5% - 2.9%

(*Id.*)

99. In addition, interest rates, as represented by U.S. Treasury yields, have been very low, reflecting in part the currency and economic crisis in Europe and the Federal Reserve Bank's monetary policy to stimulate the U.S. economy (i.e., buying U.S. Treasury securities and increasing monetary supply). (*Id.*)

100. Although Staff generally uses six different ROE estimation methodologies, Staff restricted its analysis to those methodologies employed by SWG plus the ECAPM analysis, and applied these methodologies to SWG's Proxy Group. (*Id.* at 10.) Staff performed a limited analysis in order to clearly highlight the reasons for the different ROE determinations by Staff and SWG because, generally, different ROE determinations result from the use of different estimation methods, proxy groups, and other data. (*Id.* at 8, 10.) The results of Staff's analyses are summarized in the table below:

Methodology	Range	Average
Constant Growth DCF	8.69% to 9.45%	9.04%
Three-Stage DCF	8.53% to 9.33%	8.93%
CAPM & ECAPM	7.85% to 8.26%	8.06%
Bond Yield Plus Risk Premium	9.37%	9.37%
Average		8.85%
Average Excluding CAPM & ECAPM		9.11%
Staff's Recommendation	**8.70% to 9.50%**	**9.10%**

(*Id.* at 3.)

101. In contrast to SWG's DCF analyses, Staff's analyses (a) updated the stock data through the first quarter of 2012, (b) did not use the retention growth estimate technique, and (c) applied a different third-stage dividend growth estimate for the three-stage method. (*Id.* at 11-12, 14.) Staff states that it did not consider the retention growth estimate technique because although SWG utilized this technique in this proceeding, SWG's expert argued against application of the technique in Nevada Power Company d/b/a NV Energy's ("Nevada Power")

2011 general rate case, and SWG has failed to explain its inconsistent application of the technique. (*Id.* at 12.) Staff notes that applying the retention growth technique increases the average as follows:

DCF Method	Including Retention		Excluding Retention	
	Range	Average	Range	Average
Constant	8.69% to 10.01%	9.28%	8.69% to 9.45%	9.04%
Three-Stage	8.61% to 9.41%	9.01%	8.53% to 9.33%	8.93%

(*Id.* at 13.)

102. Staff asserts that SWG's third-stage dividend growth rate of 5.78 percent is overstated and recommends 4.45 percent. (*Id.* at 14-16.) Staff states that the Energy Information Administration's ("EIA") "Annual Energy Outlook 2012" issue indicates economic growth is forecasted to be slower than historical economic growth. (*Id.* at 15.) The EIA economic growth forecast is based upon a review of several other forecasts.[13] (*Id.*) While the historical economic growth (1926 to 2011) averaged 3.24 percent, EIA forecasts a 2.55 percent growth rate as measured by the GDP. (*Id.* at 16.) Further, Staff contends SWG used a consumer price index ("CPI") measure (Treasury Inflation Protected Securities) to estimate the inflationary change in the GDP. (*Id.*) Staff recommends using the EIA's forecasted GDP price index rate of 1.9 percent, as published in "Annual Energy Outlook 2012," rather than SWG's 2.2 percent. (*Id.* at 14-16; Exhibit 29, Att. YO-5 at 12, 16-18.)

103. Staff's CAPM analysis uses a different risk-free rate and market risk premium than SWG's. (Exhibit 29 at 18-19.) Staff asserts that the risk-free rate should be the historical average 20-year U.S. Treasury Bond yield (1926—first quarter 2012) not the forecasted 30-year U.S. Treasury Bond yield. (Exhibit 29 at 18; Exhibit 29, Att. YO-10 at 13.) Using a 30-year U.S. Treasury Bond yield will increase the risk-free rate by 20 to 30 basis points. (Tr. at 241.)

[13]For example, HIS Insight Global (November 2011), Social Security Administration (August 2011), and Blue Chip Consensus (October 2011).

Staff argues SWG's derived market risk premiums are inappropriate for analytical purposes because the calculated market risk premiums significantly exceed published estimates.[14] (Exhibit 29 at 17-23.) Staff recommends a 6.6 percent market risk premium, which is the observed average for the period 1926 to 2011. (*Id.*) Staff acknowledges its market risk premium exceeds the rates cited in published reports (5.5 percent, 5.5 percent, and 4.48 percent) which reflect forecasted low inflation and low economic growth. (*Id.*) However, Staff asserts its market risk premium rate range is more conservative than SWG's 8.6 to 10.4 percent range. (Exhibit 29 at 17-23; Exhibit 29, Att. YO-9 at 3, Att. YO-10 at 10-11, Att. YO-11 at 4, 6.)

104. Additionally, Staff's recommendation incorporates the ECAPM technique. Staff asserts that the ECAPM is a common methodology and easy to employ, as it only requires a minor modification to the CAPM equation. (Exhibit 29 at 23-24.) Staff calculated the ECAPM using a standard value of 25 percent for the direct assignment of the market risk premium to SWG. (*Id.* at 24.)

105. Staff recommends modifying SWG's risk premium methodology to reflect the current forecasted 30-year U.S. Treasury Bond yield (replace SWG's 3.5 percent with 3.0 percent) and replace the long-linear regression formula with a linear regression formula. (Exhibit 29 at 26.) Staff asserts that the linear regression derived formula, which measures the difference between authorized ROEs and the U.S. 30-year Bond yields, is statistically more accurate. (*Id.* at 26-27.)

SWG's Rebuttal Position

106. In its rebuttal testimony, SWG recommends reducing its proposed ROE to 10.50 percent in order to account for the stabilization of market conditions that has occurred since

[14] Staff reviewed documents include "Market Risk Premium Used in 82 Countries in 2012: a Survey with 7,192 Answers" by IESE (5.5 percent); Duff & Phelps' "Risk Premium Report 2012" (5.5 percent); and "The Equity Risk Premium in 2012" by John R. Graham and Campbell R. Harvey (4.48 percent). (Exhibit 29 at 22-23.)

SWG filed its direct testimony. (Exhibit 33 at 11.) SWG revised its analysis to include information through July 31, 2012 and the ECAPM technique, but states that its reasonable ROE range is still 10 to 10.75 percent. (*Id.* at 13-14.) Additionally, SWG concurs with Staff that no adjustment for the GIR is warranted. (*Id.* at 47.)

107. SWG's updated analysis had a minor effect upon the original results. (*Id.* at 14.) Under the DCF analysis, both the low and mean growth estimates increased slightly (ranging from 0.2 to 0.18 percent) and the high growth estimate decreased slightly (ranging from 0.0 to 0.28 percent). (*Id.*) SWG notes that two of the three CAPM analyses showed reductions while the third analysis showed an increase. (*Id.* at 14-15.) The ECAPM results are slightly below the initial CAPM results. (*Id.* at 15.) The risk premium methodology declined slightly by 0.05 percent. (*Id.*; Exhibit 33 at Att. RBH-R-1, Att. RBH-R-3, Att. RBH-R-6.) SWG estimated that using Staff's historical 3.24 percent real GDP growth rate decreased the multi-stage DCF mean from a high growth rate range of 9.53 to 10.85 percent down to 8.95 to 10.31 percent. (Exhibit 33 at Att. RBH-R-3; Exhibit 106.)

108. SWG asserts that the following are shortcomings of BCP's DCF analyses:

a. SWG contends that BCP's focus upon the Federal Reserve target federal funds rate is misplaced. (Exhibit 33 at 49.) The federal funds rate, is an overnight interest rate and is not necessarily relevant in determining the appropriate ROE. (*Id.*)
b. SWG further asserts that BCP's DCF analysis is flawed. (*Id.* at 51.) BCP's constant growth DCF relied upon historical inputs in developing the retention growth rate rather than forecasted information. (*Id.*)
c. BCP's multiple-stage DCF uses an implied constant dividend growth rate rather than movement toward an industry average, which Value Line estimates to be 65 percent for a natural gas distribution industry. (*Id.* at 52-54.)
d. BCP's multiple-stage DCF analysis assumed that dividends are paid annually at the end of the year rather than quarterly. (*Id.* at 52, 54-55.) SWG states that simply increasing the dividend payment to semi-annually increases BCP's DCF results as follows:

	Mean	Median	Proxy Group Company Range
BCP	9.08%	9.04%	8.76% - 9.80%
SWG Revised BCP	9.25%	9.21%	8.92% - 10.02%

(*Id.* at 52, 54-55, Att. RBH-R-14.)

109. With respect to BCP's CAPM analysis, SWG asserts that it is flawed because it relied upon a historic market risk premium, and BCP's calculation is incorrect. SWG states that if the market risk premium is limited to the income-only component, it would increase to 6.60 percent, which increases the CAPM and ECAPM analyses as follows:

	CAPM		ECAPM	
	Mean	**Median**	**Mean**	**Median**
BCP	8.70%	8.66%	9.12%	9.04%
SWG Revised BCP	9.02%	8.98%	9.46%	9.38%

(*Id.* at 56-57, Att. RBH-R-15.)

110. Additionally, SWG asserts that BCP's financial ratio analysis is flawed. (Exhibit 32 at 9-11.) BCP failed to consider the deferred energy accounting interest expense, credit rating balance sheet adjustments, and presumes the ROE will be earned. (*Id.*) Further, BCP failed to consider the impact upon the credit rating agency's regulation perspective. (*Id.* at 7.)

111. With respect to Staff, SWG asserts that:

a. Staff's constant DCF analysis was developed using mismatched inputs and inappropriately excluded the retention growth technique. (*Id.* at 18, 22.)
b. Using the U.S. Treasury inflation protection securities as an inflation component of the multi-stage DCF growth rate is appropriate because such securities represent the investors' collective views regarding long-run inflation expectations. (Exhibit 33 at 29.)

112. SWG asserts that its CAPM analysis which relies upon 30-year Treasury Bonds as the risk-free rate of return is more appropriate than Staff's analysis which uses a historical market risk premium and 20-year Treasury Bonds. (*Id.* at 31-32.) This is because 30-year Treasury bonds are closer to the duration in which an equity investment is held. (*Id.* at 32.)

SWG also notes that 30-year Treasury bonds generally exceed the 20-year bonds by 55 basis points. (*Id.* at 31.)

113. SWG further asserts that Staff's criticism of SWG's market risk premiums is unfounded. (*Id.* at 42.) SWG states that using a DCF analysis to derive the market risk premium is a published methodology. (*Id.* at 35, 43-44.) Investors consider market volatility in their analysis and, therefore, adjusting historical market risk premium for increased volatility is reasonable. (*Id.* at 35-38.)

114. SWG recommends denying BCP's 25 basis point adjustment to the ROE for decoupling. (*Id.* at 58.) SWG asserts that BCP failed to address the relevant question of whether SWG is less risky in comparison to the Proxy Group—not whether it is risky with or without its rate design proposals. (*Id.*) SWG states that its risk profile is comparable to the Proxy Group. (*Id.* at 59-60, Att. RBH-R-16.)

ii. Rehearing (January 10-11, 2013)

SWG's Position

115. SWG states that if the Commission accepts SWG's corporate capital structure, then SWG recommends a ROE range of 10.0 percent to 10.75 percent, and requests a ROE of 10.65 percent within that range. (Tr. at 1379.)

116. SWG states that if the Commission affirms the capital structures set forth in the Modified Final Order, then the authorized ROEs for the NND and SND are too low because they inadequately address the leverage differential between the authorized capital structure and the Proxy Group capital structure. (Tr. at 1376-77.) SWG recommends a ROE range of 9.50 percent to 10.40 percent for the NND, and a ROE range of 10.50 percent to 11.40 percent for the SND. (Exhibit 128 at 1; Tr. at 1379.)

117. SWG states that if the NND and SND are to have separate capital structures, the Proxy Group capital structure in the Modified Final Order is inaccurate. (Tr. at 1298.) Specifically, SWG states that a weighted Proxy Group average rather than a simple Proxy Group average was developed. SWG asserts that a weighted average inappropriately provides weight to one large Proxy company. (Tr. at 1298, 1357.)

118. In addition, SWG states that the Commission's Order, which includes total capital rather than permanent capital, should have excluded short-term debt. (Tr. at 1298-99.) SWG asserts that only permanent capital (long-term capital) that finances rate base should be used. (Tr. at 1299.) Moreover, SWG states that it is inappropriate to use a single point in time—in this instance, December 31, 2011—to estimate the Proxy Group debt. SWG asserts that a multi-year average (i.e., three to five years) should have been used to mitigate any year-to-year financial variations, and variations in short-term debt due to seasonal cash flow needs. (Tr. at 1300, 1372-73, 1397.)

119. SWG testifies that the Proxy Group's five-year quarterly average total debt leverage ratio of 50.11 percent is consistent with the debt ratios implied by the median of the state commissions' authorized 2012 equity ratios for the periods January-July 2012 and August-December 2012. (Exhibit 21, Att. TKW-5 at 1; Exhibit 126; Exhibit 128 at 3-5; Tr. at 1372-73.)

120. SWG acknowledges that the Commission considered in its ROE decision the difference in leverage between the authorized capital structures and the Proxy Group. (Tr. at 1370, 1396-97.) For the SND, SWG estimates that the Commission increased the ROE by 10.3 basis points for each one percent increase in leverage relative to the Proxy Group capital structure set forth in the Modified Final Order. However, the Commission reduced the NND

ROE by 1.7 basis points for each one percent decrease in leverage relative to the Proxy Group.[15] (Exhibit 128 at 2; Tr. at 1368-71.)

121. SWG states that it based its newly proposed reasonable range of ROEs for the separate capital structures upon its own analysis of the Commission's Order regarding the ROE basis point leverage adjustment to various ROEs compared with the Proxy Group capital structure having a debt ratio of 50.11 percent. (Exhibit 128; Tr. at 1373-76.) The table below summarizes this analysis, with the baseline being the Modified Final Order, and includes the Proxy Group's December 31, 2011 capital structure:

ROE Median or Mid-point Used	ROE	NND	SND
Modified Final Order	9.55%	9.20%	9.85%
5-Year Quarterly Total Debt			
Modified Final Order Mid-Point	9.55%	9.28%	10.30%
January – July 2012 Median Authorized ROE	9.75%	10.50%	9.48%
August – December 2012 Median Authorized ROE	10.12%	10.87%	9.85%
SWG Recommended	10.65%	11.40%	10.38%

(Exhibit 126; Exhibit 128; Tr. at 1371.) SWG states that its proposed reasonable range of ROEs is based on a consolidated ROE range of 9.75 percent to 10.65 percent. (Exhibit 128 at 1; Tr. at 1377.)

122. SWG contends that the authorized equity ratio of 45.4 percent in the Commission's Modified Final Order is less than the median 51 percent equity ratio authorized in 2012 by other commissions as illustrated below.

	Median Equity Ratio	Median ROE
January - July 2012	50.82%	9.73%

[15] The increase and decrease in ROE was calculated by dividing the difference between the authorized ROE and the mid-point of the Commission's ROE range of 9.1 percent to 10.0 percent (i.e., 9.55 percent) by the difference between the NND's and SND's authorized capital structures debt percentage and the estimated capital structure for the Proxy Group (*see* Modified Final Order at paragraph 69) on December 31, 2011, which equals 54.49 percent debt and 45.51 percent equity. (Exhibit 128 at 2; Tr. at 1369.)

August – December 2012	51.65%	10.10%
	Nevada Consolidated	**Mid-Point**
PUCN	45.41%	9.55%

(Exhibit 126; Tr. at 1353-54, 1361-63.)

123. SWG asserts that equity markets reacted negatively to the Commission's decision indicating that the ROEs are too low. (Tr. at 1363.) SWG provided a statistical analysis of SWG's cumulative stock market returns compared to the Proxy Group cumulative returns for two months prior to the issuance of the Commission's Order and two months subsequent to the Commission's Order. (Tr. at 1363-66.) Prior to the issuance of the Order, SWG's total return was 2.87 percent while the Proxy Group's total return was 2.65 percent. (Exhibit 127; Tr. at 1364.) SWG asserts that following the issuance of the Order SWG significantly underperformed. (Tr. at 1364.) SWG's rate of return was a negative 3.53 percent while the Proxy Group return was a positive 0.25 percent. (Exhibit 127; Tr. at 1364.) According to SWG, this indicates a statistically significant relationship between the date of the Order and SWG's stock performance. (Tr. at 1365, 1395.)

124. SWG further contends that the financial community was aware of the capital structure issues. (Tr. at 1367.) In support, SWG references the UBS Report and the transcript from SWG's third quarter earnings conference. (Tr. at 1366.)

BCP's Position

125. BCP asserts that the Commission addressed the additional risk associated with the SND being more leveraged than the Proxy Group. (Tr. at 1417.) BCP testifies that the financial community generally expects a 10 basis point change for a one percent change in debt leverage. (Tr. at 1418.) BCP's 10 basis point estimate is based on several studies that were performed

between 1958 and 1987. (Exhibit 131; Tr. at 1418, 1439.) These studies support the range of 7.6 to 13.8 basis points per one percent change in leverage, with 10 basis points being approximately the mid-point.[16] (Tr. at 1439-40.)

Study Year	Empirical Study	Theoretical Study
1958	115	
1963	62	
1968		34
1973		75
1974		45
1977	237	
1980		109
1986		72
1987		117
Average	138	76

(Exhibit 131 at 3.)

126. The financial text also notes that a controversy exists if the relationship is linear or curvilinear. (*Id.* at 2-3.)

127. BCP further testifies that utility commissions typically consider various issues, including capital structures, in determining the appropriate authorized ROE selected from the range of reasonable ROEs. (Tr. at 1441-42.)

128. BCP testifies that it has not seen any financial reports indicating the financial community is "alarmed with the regulatory process or regulatory decisions" for SWG or any other utility regulated by the Nevada Commission. (Tr. at 1414.) BCP states that the UBS Report mentions the Commission's decision, but mere mention of the decision does not constitute alarm. BCP states that it is common for financial reports to report recent rate case decisions (e.g., amount of requested granted, authorized ROE, equity ratio, or hot button issues).

[16] The basis points expressed in the table are for the entire 10 percent change in leverage studied (i.e., 40 percent to 50 percent). The range was divided by 10 to arrive at the basis points per 1 percent in leverage. (Exhibit 131 at 3.)

(*Id.*)

129. BCP asserts that, in this particular case, whether a quarterly average or one point in time method is used in the Proxy Group to address short-term debt seasonality should not be a major concern. (Tr. at 1459-60.) Nonetheless, BCP states that it is better when comparing SWG and the Proxy Group to analyze the same data either at one point in time or over an average period of time. (Tr. at 1460.)

Staff's Position

130. Staff asserts that the Modified Final Order's range of reasonable ROEs of 9.10 percent to 10.0 percent is still appropriate. (Tr. at 1535-36.) The range is based upon the fully vetted testimony provided in this proceeding. (Tr. at 1536.)

131. Staff recommends a ROE of 9.85 for the SND and 9.30 percent for the NND. (Exhibit 135 at 3, 7; Tr. at 1492, 1495.) Staff states that its recommended ROE for the NND reflects Staff's recommended capital structure in the NND, which is slightly more leveraged than the 34.36 percent debt in the Modified Final Order. (Tr. at 1495.)

132. Staff argues that SWG's pre- and post-draft Order stock market price analysis is too simplistic. (Tr. at 1499.) Staff argues that the change in total market return referenced by SWG was caused by macroeconomic issues, industry-specific issues, and SWG's third quarter earnings report. SWG's third quarter earnings report is important to investors as it indicates how the utility is performing. (Tr. at 1498-99.) For instance, a comparison of NiSource's (a Proxy utility) stock price to SWG's stock price illustrates a similar pattern in the market return for NiSource prior to and after the issuance of the Order. (*Id.*; Exhibit 137.)

133. In responding to SWG's criticisms of the Modified Final Order's assessment of the Proxy Group's capital structures, Staff notes that a simple average based on a Proxy Group's

corporate capital structure differentiates for a company's size by not giving more weight to larger companies. (Tr. at 1521.) In addition, Staff states that short-term debt should be included in the assessment because it is a form of debt financing. (Tr. at 1522.) Customer deposits are likely considered short-term debt because the funds are generally held for less than a year. (Tr. at 1475.)

134. Staff also asserts that it is preferable to maintain consistency between the measurement of the capital structure for SWG and the Proxy Group. (Tr. at 1529.) Staff states that, on this record, SWG has only provided its information for one point in time and not the five-year quarterly average SWG used for its Proxy Group. (Tr. at 1530.) Staff also states that the rate base component of cash working capital should be considered a short-term investment. (Tr. at 1474-75.)

SWG's Rebuttal Position

135. SWG continues to recommend using the five-year quarterly average Proxy Group capital structure compared to SWG at one point in time as a benchmark. (Tr. at 1553, 1555, 1567-68.) According to SWG, the five-year quarterly average mitigates variations in financial performance and addresses the issue of short-term debt seasonality. (Tr. at 1553, 1567.) SWG contends that the Proxy Group's five-year quarterly average capital structure, with an equity ratio of 49.64 percent[17] is consistent with both the estimated June 30, 2012[18] Proxy Group equity ratio of 50.3 percent and the January 2012 through July 2012 average authorized equity ratio of 50.8 percent. (Exhibit 126; Exhibit 139; Tr. at 1555-56.)

[17] SWG calculated for the proxy group, using a five-year quarterly average, a debt ratio of 50.11 percent; common equity of 49.64 percent and preferred stock of 0.25 percent. (Exhibit 21, Att. TKW-5 at 1.) In including short-term debt, SWG states the proxy group capital structure includes 50.11 percent debt. By default, SWG presumes the remaining 49.89 percent common equity for it does not have any preferred stock. (Exhibit 5, Vol. 1, Statement F at 1, 3; Exhibit 5, Vol. 2, Statement F at 1, 3; Exhibit 21, Att. TKW-5 at 1; Exhibit 128 at 3-6.)
[18] June 30th was selected for the proxy group as it was the closest reporting period to the certification end date of May 31, 2012. (Tr. at 1566-67.)

Commission Discussion and Findings

136. The process of establishing rates for a utility requires that the Commission establish a rate of return on the equity portion of the utility's capital structure. To arrive at a decision as to the appropriate ROE, this Commission relies on the NRS, NAC, and two seminal U.S. Supreme Court decisions, *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679 (1923) and *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944). The authorized ROE should be sufficient for the public utility to maintain financial integrity and capital attraction.

137. In the *Hope* decision, the Court re-affirmed the *Bluefield* standard in finding that it is not the method for estimating the ROE that determines the reasonableness of the ROE, but rather it is the result and impact of the result on the public utility.

138. In establishing SWG's ROE, the Commission relies upon expert testimony and evidence which applies principles of finance, accounting and economics to the cost of a particular utility's common equity. This evidence includes the results of each expert's ROE analyses, the experts' judgment in assessing macroeconomic conditions, capital markets, and SWG's particular circumstances (e.g., capital structure, risk profile, and regulatory environment); and each expert's critique of other experts' ROE analyses.

139. The ROEs originally recommended by the parties in this proceeding range from 9.1 percent to 10.5 percent, and were based on market conditions and an analysis of the authorized rates of return of comparable utilities, with consideration of SWG's particular circumstances.

	Range	ROE
SWG	10.00% - 10.75%	10.50%
BCP	8.7% - 9.7%	9.2%
Staff – w/o Retention DCF	8.7% - 9.5%	9.1%

Staff – with Retention DCF	8.7% - 10%	9.2% [19]

140. The ROE needs to reflect current and future economic conditions. The ROE study filed by SWG does not reflect future economic conditions. On the other hand, Staff and BCP view economic growth to be slow and believe that interest rates will remain low into 2014. SWG's original recommendation also relied primarily upon the DCF analysis which utilizes unrealistically high growth rates. Further, the multi-stage third step growth was premised upon forecasted economic growth which significantly exceeds published forecasted rates and historical GDP growth. In addition, the CAPM analysis filed by SWG relied upon market risk premiums that are unreasonably high. Therefore, SWG's use of overstated inputs appears to have produced results that are substantially higher than those calculated by BCP and Staff using the same Proxy Group of companies. The use of these inputs was not successfully defended by SWG.

141. The Commission finds that a reasonable range of ROEs is 9.1 percent to 10.0 percent, based on the evidence presented in BCP's and Staff's testimony and the modifications made by SWG in rebuttal to the analyses.

142. The Commission must now determine an appropriate ROE for SWG within the approved reasonable range. In making this determination, the Commission recognizes the differences between the SND and NND capital structure as adjusted by this order when compared to the Proxy Group.

143. During the rehearing, there was considerable discussion regarding the relationship of the ROE to the debt and equity ratios. The evidence presented at rehearing included a compilation of studies on leverage impacts upon ROEs. BCP presented a compilation study that identified significant variability in estimated ROE effects that ranged from 3.4 basis points to

[19] Calculated using Staff's methodology of averaging the constant DCF, three-stage DCF, and bond yield plus risk premium average results. (Exhibit 29 at 3, 12-13,17.)

23.7 basis points per each 1 percent change in leverage. The reason for the variability was not noted in the study. The study's publication dates (1958 through 1987) indicate that a broad range of economic conditions were potentially experienced during the study period, with the mid-range of 7.6 basis points to 13.8 basis points representing some average economic conditions. For example, the most recent studies (1986 and 1987 studies), which were published over 25 years ago, may have included the period between 1980 to 1985 when the U.S. Treasury 30-year bond yields exceeded 10 percent. These yields are more than twice the 2011 interest rates. The results of the studies suggest significantly different economic conditions than the conditions that exist today. BCP's and Staff's testimony in this proceeding indicates that historic economic conditions may not be a reliable indicator of current circumstances. Therefore, the study is weighted accordingly.[20]

144. With respect to SWG's assertions about the relationship between debt ratios and ROE discussed above, the Commission notes that this analysis is one of many factors when determining an appropriate ROE. The Commission considers a number of factors in addition to the debt and equity ratios, including ROE studies, the general economic climate, the status of financial markets, and any specific facts and circumstances pertaining to the particular utility. The Commission also considers any recommendations by experts. The recommendations by the experts are also grounded in the ROE studies and each expert's professional judgment regarding all of the above factors. The weight of the evidence is then applied to applicable law. SWG's analysis and recommended ROE considered only the debt and equity ratio factor.

145. Based on testimony presented during the rehearing, the Commission finds it is appropriate to utilize the five-year quarterly average of the Proxy Group debt ratio. This

[20] SWG states in its direct case that the U.S. Treasury 30-year bond yields in 1980 range from approximately 11 to 12 percent, which increased to nearly 14 percent in 1982, after which yields generally declined to an approximate range of 4 to 4.5 percent in 2011. (Exhibit 24 at Att. RBH-7.)

approach more accurately reflects the seasonal variations in short-term debt. The calculations are shown in the table below, and result in a less leveraged capital structure for the Proxy Group. The total debt ratio included in SWG's Application of 50.11 percent does not distinguish between long-term and short-term debt, as illustrated in the table below. (*See* Exhibit 21, Att. TKW-5 at 1.)

	Direct Assignment		**Proxy Group**	
Component	**SND**	**NND**	**November 7, 2012 Order**	**Rehearing Order**
Long-Term Debt	54.99%	37.15%	44.18%	--
Customer Deposits / Short-Term Debt	2.27%	3.79%	10.31%	--
Total Debt	57.26%	40.94%	54.49%	50.11%
Preferred Stock	0.00%	0.00%	0.22%	0.25%
Common Equity	42.74%	59.06%	45.29%	49.64%
Total Equity	42.74%	59.06%	45.51%	49.89%
Total	100.00%	100.00%	100.00%	100.00%

146. Based on the Proxy Group capital structure, the Commission finds that an ROE of 10.0 percent is appropriate for the SND. As noted in the table above, the SND has a more leveraged capital structure relative to the Proxy Group, with 57.40 percent debt compared to a debt ratio of 50.11 percent for the Proxy Group. The Commission finds that a ROE of 10.0 percent meets the requirement of maintaining the financial integrity of the SND and is sufficient to attract investment.

147. The NND is less leveraged than either the Proxy Group or the SND. The Commission finds that an ROE of 9.30 percent is appropriate for the NND. The Commission finds that a 9.30 percent ROE meets the requirement of maintaining the financial integrity of the

NND and is sufficient to attract investment.

148. The Commission notes that these findings are based on the totality of evidence including the ROE studies, general economic conditions, and SWG's particular business. The Commission finds that a ROE of 9.30 percent for the NND and a ROE of 10.0 percent for SND (with an estimated effective ROE of 9.89 percent) balances the interests of the ratepayers and shareholders, and results in just and reasonable rates. Moreover, these ROEs will allow the shareholders an opportunity to earn a return commensurate with other investments of similar risk. The Commission further finds that the authorized ROEs are consistent with *Hope* and *Bluefield*.[21]

149. The Commission finds that an adjustment for SWG's revenue decoupling mechanism is unnecessary. All of the companies in the Proxy Group have some form of a rate stabilization mechanism in place; thus, the lower risk associated with revenue decoupling is accounted for in the results of the ROE study.

VI. DEPRECIATION

A. Account 367 – Transmission Mains

SWG's Position

150. SWG requests that the Commission modify the depreciation inputs for Account 367 (transmission mains) in the SND as follows:

a. Change the annual accrual rate from 2.23 percent to 1.73 percent, which results in a decrease in the previously approved accrual amount of $2,421,248 to $1,878,368 (Exhibit 2, Vol. IV at App. B);
b. Change the net salvage rate from negative 15 percent to negative 20 percent (*Id.* at App. C); and
c. Change the survivor curve (or "Iowa Curve")[22] from a 55-year life with R2.5

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[21] *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679 (1923) and *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).
[22] The survivor curve is the percentage of property remaining in service at various age intervals (i.e., Iowa Curves), which are a descriptive standard for the life characteristics of industrial property. (Exhibit 2, Vol. IV at 4.)

SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
CITY OF EL PASO'S SEVENTEENTH REQUEST FOR INFORMATION
QUESTION NOS. CEP 17-1 THROUGH CEP 17-23

CEP 17-14:

Reference the Rebuttal testimony of Jennifer E. Nelson at 52, footnote 166, pleas provide a copy of each of the articles referenced.

RESPONSE:

Please see CEP 17-14, Attachment 1a, 1b, and 1c.

Preparer: Jennifer E. Nelson Title: Assistant Vice President – Concentric Energy Advisers

Sponsor: Jennifer E. Nelson Title: Assistant Vice President – Concentric Energy Advisers

The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts

Robert S. Harris and Felicia C. Marston

Using expectational data from financial analysts, we estimate a market risk premium for US stocks. Using the S&P 500 as a proxy for the market portfolio, the average market risk premium is found to be 7.14% above yields on long-term US government bonds over the period 1982-1998. This risk premium varies over time; much of this variation can be explained by either the level of interest rates or readily available forward-looking proxies for risk. The market risk premium appears to move inversely with government interest rates suggesting that required returns on stocks are more stable than interest rates themselves. [JEL: G31, G12]

■The notion of a market risk premium (the spread between investor required returns on safe and average risk assets) has long played a central role in finance. It is a key factor in asset allocation decisions to determine the portfolio mix of debt and equity instruments. Moreover, the market risk premium plays a critical role in the Capital Asset Pricing Model (CAPM), the most widely used means of estimating equity hurdle rates by practitioners. In recent years, the practical significance of estimating such a market premium has increased as firms, financial analysts, and investors employ financial frameworks to analyze corporate and investment performance. For instance, the increased use of Economic Value Added (EVA®) to assess corporate performance has provided a new impetus for estimating capital costs.

The most prevalent approach to estimating the market risk premium relies on some average of the historical spread between returns on stocks and bonds.[1] This choice has some appealing characteristics but is subject to many arbitrary assumptions such as the relevant period for taking an average. Compounding the difficulty of using historical returns is the well noted fact that standard models of consumer choice would predict much lower spreads between equity and debt returns than have occurred in US markets—the so called equity risk premium puzzle (see Welch, 2000 and Siegel and Thaler, 1997). In addition, theory calls for a forward-looking risk premium that could well change over time.

This paper takes an alternate approach by using expectational data to estimate the market risk premium. The approach has two major advantages for practitioners. First, it provides an independent estimate that can be compared to historical averages. At a minimum, this can help in understanding likely ranges for risk premia. Second, expectational data allow investigation of changes in risk premia over time. Such time variations in risk premia serve as important signals from investors that should affect a host of financial decisions. This paper provides new tests of whether changes in risk premia over time are linked to forward-looking measures of risk. Specifically, we look at the

Robert S. Harris is the C. Stewart Sheppard Professor of Business Administration and Felicia C. Marston is an Associate Professor at the University of Virginia, Charlottesville, VA 22906.

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[1] Bruner, Eades, Harris, and Higgins (1998) provide survey evidence on both textbook advice and practitioner methods for estimating capital costs. As testament to the market for cost of capital estimates, Ibbotson Associates (1998) publishes a "Cost of Capital Quarterly."

relationship between the risk premium and four *ex-ante* measures of risk: the spread between yields on corporate and government bonds, consumer sentiment about future economic conditions, the average level of dispersion across analysts as they forecast corporate earnings, and the implied volatility on the S&P500 Index derived from options data.

Section I provides background on the estimation of equity required returns and a brief discussion of current practice in estimating the market risk premium. In Section II, models and data are discussed. Following a comparison of the results to historical returns in Section III, we examine the time-series characteristics of the estimated market premium in Section IV. Finally, conclusions are offered in Section V.

I. Background

The notion of a "market" required rate of return is a convenient and widely used construct. Such a rate (k) is the minimum level of expected return necessary to compensate investors for bearing the average risk of equity investments and receiving dollars in the future rather than in the present. In general, k will depend on returns available on alternative investments (e.g., bonds). To isolate the effects of risk, it is useful to work in terms of a market risk premium (rp), defined as

$$rp = k - i, \tag{1}$$

where i = required return for a zero risk investment.

Lacking a superior alternative, investigators often use averages of historical realizations to estimate a market risk premium. Bruner, Eades, Harris, and Higgins (1998) provide recent survey results on best practices by corporations and financial advisors. While almost all respondents used some average of past data in estimating a market risk premium, a wide range of approaches emerged. "While most of our 27 sample companies appear to use a 60+ year historical period to estimate returns, one cited a window of less than ten years, two cited windows of about ten years, one began averaging with 1960, and another with 1952 data" (p. 22). Some used arithmetic averages, and some used geometric. This historical approach requires the assumptions that past realizations are a good surrogate for future expectations and, as typically applied, that the risk premium is constant over time. Carleton and Lakonishok (1985) demonstrate empirically some of the problems with such historical premia when they are disaggregated for different time periods or groups of firms. Siegel (1999) cites additional problems of using historical returns and argues that equity premium estimates from past data are likely too high. As Bruner et al. (1998) point out, few respondents cited use of expectational data to supplement or replace historical returns in estimating the market premium.

Survey evidence also shows substantial variation in empirical estimates. When respondents gave a precise estimate of the market premium, they cited figures from 4% to over 7% (Bruner et al., 1998). A quote from a survey respondent highlights the range in practice. "In 1993, we polled various investment banks and academic studies on the issue as to the appropriate rate and got anywhere between 2 and 8%, but most were between 6% and 7.4%." (Bruner et al., 1998). An informal sampling of current practice also reveals large differences in assumptions about an appropriate market premium. For instance, in a 1999 application of EVA analysis, Goldman Sachs Investment Research specifies a market risk premium of "3% from 1994-1997 and 3.5% from 1998-1999E for the S&P Industrials" (Goldman Sachs, 1999). At the same time, an April 1999 phone call to Stern Stewart revealed that their own application of EVA typically employed a market risk premium of 6%. In its application of the CAPM, Ibbotson Associates (1998) uses a market risk premium of 7.8%. Not surprisingly, academics do not agree on the risk premium either. Welch (2000) surveyed leading financial economists at major universities. For a 30-year horizon, he found a mean risk premium of 7.1% but a range from 1.5% to 15% with an interquartile range of 2.4% (based on 226 responses).

To provide additional insight on estimates of the market premium, we use publicly available expectational data. This expectational approach employs the dividend growth model (hereafter referred to as the discounted cash flow (DCF) model) in which a consensus measure of financial analysts' forecasts (FAF) of earnings is used as a proxy for investor expectations. Earlier work has used FAF in DCF models[2] but generally has covered a span of only a few years due to data availability.

II. Models and Data

The simplest and most commonly used version of the DCF model is employed to estimate shareholders' required rate of return, k, as shown in Equation (2):

[2]See Malkiel (1982), Brigham, Vinson, and Shome (1985), Harris (1986), and Harris and Marston (1992). The DCF approach with analysts' forecasts has been used frequently in regulatory settings. Ibbotson Associates (1998) use a variant of the DCF model with forward-looking growth rates; however, they do this as a separate technique and not as part of the CAPM. For their CAPM estimates, they use historical averages for the market risk premium.

$$k = \left(\frac{D_1}{P_0}\right) + g, \tag{2}$$

where D_1 = dividend per share expected to be received at time one, P_0 = current price per share (time 0), and g = expected growth rate in dividends per share.[3] A primary difficulty in using the DCF model is obtaining an estimate of g, since it should reflect market expectations of future performance. This paper uses published FAF of long-run growth in earnings as a proxy for g. Equation (2) can be applied for an individual stock or any portfolio of companies. We focus primarily on its application to estimate a market premium as proxied by the S&P500.

FAF comes from IBES Inc. The mean value of individual analysts' forecasts of five-year growth rate in EPS is used as the estimate of g in the DCF model. The five-year horizon is the longest horizon over which such forecasts are available from IBES and often is the longest horizon used by analysts. IBES requests "normalized" five-year growth rates from analysts in order to remove short-term distortions that might stem from using an unusually high or low earnings year as a base. Growth rates are available on a monthly basis.

Dividend and other firm-specific information come from COMPUSTAT. D_1 is estimated as the current indicated annual dividend times $(1+g)$. Interest rates (both government and corporate) are from Federal Reserve Bulletins and *Moody's Bond Record*. Exhibit 1 describes key variables used in the study. Data are used for all stocks in the *Standard and Poor's 500* stock (S&P500) index followed by IBES. Since five-year growth rates are first available from IBES beginning in 1982, the analysis covers the period from January 1982-December 1998.

The approach used is generally the same approach as used in Harris and Marston (1992). For each month, a market required rate of return is calculated using each dividend-paying stock in the S&P500 index for which data are available. As additional screens for reliability of data, in a given month we eliminate a firm if there are fewer than three analysts' forecasts or if the standard deviation around the mean forecast exceeds 20%. Combined, these two screens eliminate fewer than 20 stocks a month. Later we report on the sensitivity of the results to various screens. The DCF model in Equation (2) is applied to each stock and the results weighted by market value of equity to produce the market-required return. The risk premium is constructed by subtracting the interest rate on government bonds.

We weighted 1998 results by year-end 1997 market values since the monthly data on market value did not extend through this period. Since data on firm-specific dividend yields were not available for the last four months of 1998 at the time of this study, the market dividend yield for these months was estimated using the dividend yield reported in the *Wall Street Journal* scaled by the average ratio of this figure to the dividend yield for our sample as calculated in the first eight months of 1998. Adjustments were then made using growth rates from IBES to calculate the market required return. We also estimated results using an average dividend yield for the month that employed the average of the price at the end of the current and prior months. These average dividend yield measures led to similar regression coefficients as those reported later in the paper.

For short-term horizons (quarterly and annual), past research (Brown, 1993) finds that on average analysts' forecasts are overly optimistic compared to realizations. However, recent research on quarterly horizons (Brown, 1997) suggests that analysts' forecasts for S&P500 firms do not have an optimistic bias for the period 1993-1996. There is very little research on the properties of five-year growth forecasts, as opposed to shorter horizon predictions. Boebel (1991) and Boebel, Harris, and Gultekin (1993) examine possible bias in analysts' five-year growth rates. These studies find evidence of optimism in IBES growth forecasts. In the most thorough study to date, Boebel (1991) reports that this bias seems to be getting smaller over time. His forecast data do not extend into the 1990s.

Analysts' optimism, if any, is not necessarily a problem for the analysis in this paper. If investors share analysts' views, our procedures will still yield unbiased estimates of required returns and risk premia. In light of the possible bias, however, we interpret the estimates as "upper bounds" for the market premium.

This study also uses four very different sources to create *ex ante* measures of equity risk at the market

[3]Our methods follow Harris (1986) and Harris and Marston (1992) who discuss earlier research and the approach employed here, including comparisons of single versus multistage growth models. Since analysts' forecast growth in earnings per share, their projections should incorporate the anticipated effects of share repurchase programs. Dividends per share would grow at the same rate as EPS as long as companies manage a constant ratio of dividends to earnings on a per share basis. Based on S&P500 figures (see the Standard and Poor's website for their procedures), the ratio of DPS to EPS was .51 during the period 1982-89 and .52 for the period 1990-98. Lamdin (2001) discusses some issues if share repurchases destroy the equivalence of EPS and DPS growth rates. Theoretically, i is a risk-free rate, though its empirical proxy is only a "least risk" alternative that is itself subject to risk. For instance, Asness (2000) shows that over the 1946-1998 period, bond volatility (in monthly realized returns) has increased relative to stock volatility, which would be consistent with a drop in the equity market premium.

Exhibit 1. Variable Definitions

k	=	Equity required rate return.
P_0	=	Price per share.
D_1	=	Expected dividend per share measured as current indicated annual dividend from COMPUSTAT multiplied by $(1 + g)$.
g	=	Average financial analysts' forecast of five-year growth rate in earnings per share (from IBES).
i	=	Yield to maturity on long-term US government obligations (source: Federal Reserve, 30-year constant maturity series).
rp	=	Equity risk premium calculated as $rp = k - i$.
BSPREAD	=	spread between yields on corporate and government bonds, BSPREAD = yield to maturity on long-term corporate bonds (Moody's average across bond rating categories) minus i.
CON	=	Monthly consumer confidence index reported by the Conference Board (divided by 100).
DISP	=	Dispersion of analysts' forecasts at the market level.
VOL	=	Volatility for the S+P500 index as implied by options data.

level. The first proxy comes from the bond market and is calculated as the spread between corporate and government bond yields (BSPREAD). The rationale is that increases in this spread signal investors' perceptions of increased riskiness of corporate activity that would be translated to both debt and equity owners. The second measure, CON, is the consumer confidence index reported by the Conference Board at the end of the month. While the reported index tends to be around 100, we rescale CON as the actual index divided by 100. We also examined use of CON as of the end of the prior month; however, in regression analysis, this lagged measure generally was not statistically significant in explaining the level of the market risk premium.[4] The third measure, DISP, measures the dispersion of analysts' forecasts. Such analyst disagreement should be positively related to perceived risk since higher levels of uncertainty would likely generate a wider distribution of earnings forecasts for a given firm. DISP is calculated as the average of firm-specific standard deviations for each stock in the S&P500 covered by IBES. The firm-specific standard deviation is calculated based on the dispersion of individual analysts' growth forecasts around the mean of individual forecasts for that company in that month. DISP also was estimated using a value-weighted measure of analyst dispersion for the firms in our sample. The results reported use the equally weighted version but similar patterns were obtained with both constructions.[5] Our final measure, VOL, is the implied volatility on the S&P500 index. As of the beginning of the month, a dividend-adjusted Black Scholes Formula is used to estimate the implied volatility in the S&P500 index option contract, which expires on the third Friday of the month. The call premium, exercise price, and the level of the S&P500 index are taken from the *Wall Street Journal*, and treasury yields come from the Federal Reserve. Dividend yield comes from DRI. The option contract that is closest to being at the money is used.

III. Estimates of the Market Premium

Exhibit 2 reports both required returns and risk premia by year (averages of monthly data). The estimated risk premia are positive, consistent with equity owners demanding additional rewards over and above returns on debt securities. The average expectational risk premium (1982 to 1998) over

[4]We examined two other proxies for Consumer Confidence. The Conference Board's Consumer Expectations Index yielded essentially the same results as those reported. The University of Michigan's Consumer Sentiment Indices tended to be less significantly linked to the market risk premium, though coefficients were still negative.

[5]For the regressions reported in Exhibit 6, the value-weighted dispersion measure actually exhibited more explanatory power. For regressions using the Prais-Winsten method (see footnote 7), the coefficient on DISP was not significant in 2 of the 4 cases.

Exhibit 2. Bond Market Yields, Equity Required Return, and Equity Risk Premium, 1982-1998

Values are averages of monthly figures in percent. *i* is the yield to maturity on long-term government bonds, *k* is the required return on the S&P500 estimated as a value weighted average using a discounted cash flow model with analysts' growth forecasts. The risk premium $rp = k - i$. The average of analysts' growth forecasts is *g*. *Div yield* is expected dividend per share divided by price per share.

Year	Div. Yield	*g*	*k*	*i*	*rp = k - i*
1982	6.89	12.73	19.62	12.76	6.86
1983	5.24	12.60	17.86	11.18	6.67
1984	5.55	12.02	17.57	12.39	5.18
1985	4.97	11.45	16.42	10.79	5.63
1986	4.08	11.05	15.13	7.80	7.34
1987	3.64	11.01	14.65	8.58	6.07
1988	4.27	11.00	15.27	8.96	6.31
1989	3.95	11.08	15.03	8.45	6.58
1990	4.03	11.69	15.72	8.61	7.11
1991	3.64	11.99	15.63	8.14	7.50
1992	3.35	12.13	15.47	7.67	7.81
1993	3.15	11.63	14.78	6.60	8.18
1994	3.19	11.47	14.66	7.37	7.29
1995	3.04	11.51	14.55	6.88	7.67
1996	2.60	11.89	14.49	6.70	7.79
1997	2.18	12.60	14.78	6.60	8.17
1998	1.80	12.95	14.75	5.58	9.17
Average	3.86	11.81	15.67	8.53	7.14

government bonds is 7.14%, slightly higher than the 6.47% average for 1982 to 1991 reported by Harris and Marston (1992). For comparison purposes, Exhibit 3 contains historical returns and risk premia. The average expectational risk premium reported in Exhibit 2 is approximately equal to the arithmetic (7.5%) long-term differential between returns on stocks and long-term government bonds.[6]

Exhibit 2 shows the estimated risk premium changes over time, suggesting changes in the market's perception of the incremental risk of investing in equity rather than debt securities. Scanning the last column of Exhibit 2, the risk premium is higher in the 1990s than earlier and especially so in late 1997 and 1998. Our DCF results provide no evidence to support the notion of a declining risk premium in the 1990s as a driver of the strong run up in equity prices.

A striking feature in Exhibit 2 is the relative stability of the estimates of *k*. After dropping (along with interest rates) in the early and mid-1980s, the average annual value of *k* has remained within a 75 basis point range around 15% for over a decade. Moreover, this stability arises despite some variability in the

[6]Interestingly, for the 1982-1996 period the arithmetic spread between large company stocks and long-term government bonds was only 3.3% per year. The downward trend in interest rates resulted in average annual returns of 14.1% on long-term government bonds over this horizon. Some (e.g., Ibbotson, 1997) argue that only the income (not total) return on bonds should be subtracted in calculating risk premia.

Exhibit 3. Average Historical Returns on Bonds, Stocks, Bills, and Inflation in the US, 1926-1998

Historical Return Realizations	Geometric Mean	Arithmetic Mean
Common Stock (Large Company)	11.2%	13.2%
Long-term Government Bonds	5.3	5.7
Treasury Bills	3.8	3.8
Inflation Rate	3.1	3.2

Source: Ibbotson Associates, Inc., *1999 Stocks, Bonds, Bills and Inflation*, 1999 Yearbook.

underlying dividend yield and growth components of k as Exhibit 2 illustrates. The results suggest that k is more stable than government interest rates. Such relative stability of k translates into parallel changes in the market risk premium. In a subsequent section, we examine whether changes in our market risk premium estimates appear linked to interest rate conditions and a number of proxies for risk.

We explored the sensitivity of the results to our screening procedures in selecting companies. The reported results screen out all non-dividend paying stocks on the premise that use of the DCF model is inappropriate in such cases. The dividend screen eliminates an average of 55 companies per month. In a given month, we also screen out firms with fewer than three analysts' forecasts, or if the standard deviation around the mean forecast exceeds 20%. When the analysis is repeated without any of the three screens, the average risk premium over the sample period increased by only 40 basis points, from 7.14% to 7.54%. The beta of the sample firms also was estimated and the sample average was one, suggesting that the screens do not systematically remove low or high-risk firms. (Specifically, using firms in the screened sample as of December 1997 (the last date for which we had CRSP return data), we used ordinary least squares regressions to estimate beta for each stock using the prior 60 months of data and the CRSP return (SPRTRN) as the market index. The value-weighted average of the individual betas was 1.00.)

The results reported here use firms in the S&P500 as reported by COMPUSTAT in September 1998. This could create a survivorship bias, especially in the earlier months of the sample. We compared our current results to those obtained in Harris and Marston (1992) for which there was data to update the S&P500 composition each month. For the overlapping period, January 1982-May 1991, the two procedures yield the same average market risk premium, 6.47%. This suggests that the firms departing from or entering the S&P500 index do so for a number of reasons with no discernable effect on the overall estimated S&P500 market risk premium.

IV. Changes in the Market Risk Premium Over Time

With changes in the economy and financial markets, equity investments may be perceived to change in risk. For instance, investor sentiment about future business conditions likely affects attitudes about the riskiness of equity investments compared to investments in the bond markets. Moreover, since bonds are risky investments themselves, equity risk premia (relative to bonds) could change due to changes in perceived riskiness of bonds, even if equities displayed no shifts in risk.

In earlier work covering the 1982-1991 period, Harris and Marston (1992) reported regression results indicating that the market premium decreased with the level of government interest rates and increased with the spread between corporate and government bond yields (BSPREAD). This bond yield spread was interpreted as a time series proxy for equity risk. In this paper, we introduce three additional *ex ante* measures of risk shown in Exhibit 1: CON, DISP, and VOL. The three measures come from three independent sets of data and are supplied by different agents in the economy (consumers, equity analysts, and investors (via option and share price data)). Exhibit 4 provides summary data on all four of these risk measures.

Exhibit 5 replicates and updates earlier analysis by Harris and Marston (1992).[7] The results confirm the earlier patterns. For the entire sample period, Panel A shows that risk premia are negatively related to interest rates. This negative relationship is also true for both

[7]OLS regressions with levels of variables generally showed severe autocorrelation. As a result, we used the Prais-Winsten method (on levels of variables) and also OLS regressions on first differences of variables. Since both methods yielded similar results and the latter had more stable coefficients across specifications, we report only the results using first differences. Tests using Durbin-Watson statistics from regressions in Exhibits 5 and 6 do not accept the hypothesis of autocorrelated errors (tests at .01 significance level, see Johnston, 1984). We also estimated the first difference model without an intercept and obtained estimates almost identical to those reported.

Exhibit 4. Descriptive Statistics on *Ex Ante* Risk Measures

Entries are based on monthly data. BSPREAD is the spread between yields on long-term corporate and government bonds. CON is the consumer confidence index. DISP measures the dispersion of analysts' forecasts of earnings growth. VOL is the volatility on the S&P500 index implied by options data. Variables are expressed in decimal form, (e.g., 12% = .12).

	Panel A. Variables are Monthly Levels			
	Mean	**Standard Deviation**	**Minimum**	**Maximum**
BSPREAD	.0123	.0040	.0070	.0254
CON	.9504	.2242	.473	1.382
DISP	.0349	.0070	.0285	.0687
VOL	.1599	.0697	.0765	.6085
	Panel B. Variables are Monthly Changes			
	Mean	**Standard Deviation**	**Minimum**	**Maximum**
BSPREAD	-.00001	.0011	-.0034	.0036
CON	.0030	.0549	-.2300	.2170
DISP	-.00002	.0024	-.0160	.0154
VOL	-.0008	.0592	-.2156	.4081
	Panel C. Correlation Coefficients for Monthly Changes			
	BSPREAD	**CON**	**DISP**	**VOL**
BSPREAD	1.00	-.16**	.054	.22*
CON	-.16**	1.00	.065	-.09
DISP	.054	.065	1.00	.027
VOL	.22*	-.09	.027	1.00

**Significantly different from zero at the .05 level.
*Significantly different from zero at the .01 level.

the 1980s and 1990s as displayed in Panels B and C. For the entire 1982 to 1998 period, the addition of the yield spread risk proxy to the regressions lowers the magnitude of the coefficient on government bond yields, as can be seen by comparing Equations (1) and (2) of Panel A. Furthermore, the coefficient of the yield spread (0.488) is itself significantly positive. This pattern suggests that a reduction in the risk differential between investment in government bonds and in corporate bonds is translated into a lower equity market risk premium.

In major respects, the results in Exhibit 5 parallel earlier findings. The market risk premium changes over time and appears inversely related to government interest rates but is positively related to the bond yield spread, which proxies for the incremental risk of investing in equities as opposed to government bonds. One striking feature is the large negative coefficients on government bond yields. The coefficients indicate the equity risk premium declines by over 70 basis points for a 100 basis point increase in government interest rates.[8] This inverse relationship suggests

[8]The Exhibit 5 coefficients on i are significantly different from −1. 0 suggesting that equity required returns do respond to interest rate changes. However, the large negative coefficients imply only minor adjustments of required returns to interest rate changes since the risk premium declines. In earlier work (Harris and Marston, 1992) the coefficient was significantly negative but not as large in absolute value. In that earlier work, we reported results using the Prais-Winsten estimators. When we use that estimation technique and recreate the second regression in Exhibit 5, the coefficient for i is -.584 (t = - 12.23) for the entire sample period 1982-1998.

Exhibit 5. Changes in the Market Equity Risk Premium Over Time

The exhibit reports regression coefficients (t-values). Regression estimates use all variables expressed as monthly changes to correct for autocorrelation. The dependent variable is the market equity risk premium for the S&P500 index. BSPREAD is the spread between yields on long-term corporate and government bonds. The yield to maturity on long-term government bonds is denoted as i. For purposes of the regression, variables are expressed in decimal form, (e.g., 12% = .12).

Time Period	Intercept	i	BSPREAD	R^2
A. 1982-1998	-.0002 (-1.49)	-.869 (-16.54)		.57
	-.0002 (-1.11)	-.749 (-11.37)	.488 (2.94)	.59
B. 1980s	-.0005 (-1.62)	-.887 (-10.97)		.56
	-.0004 (-1.24)	-.759 (-7.42)	.508 (1.99)	.57
C. 1990s	-.0000 (-0.09)	-.840 (-13.78)		.64
	-.0000 (0.01)	-.757 (-9.85)	.347 (1.76)	.65

Exhibit 6. Changes in the Market Equity Risk Premium Over Time and Selected Measures of Risk

The exhibit reports regression coefficients (t-values). Regression estimates use all variables expressed as monthly changes to correct for autocorrelation. The dependent variable is the market equity risk premium for the S&P500 index. BSPREAD is the spread between yields on long-term corporate and government bonds. The yield to maturity on long-term government bonds is denoted as i. CON is the consumer confidence index. DISP measures the dispersion of analysts' forecasts of earnings growth. VOL is the volatility on the S&P500 index implied by options data. For purposes of the regression, variables are expressed in decimal form, (e.g., 12% = .12).

Time Period		Intercept	i	BSPREAD	CON	DISP	VOL	Adj. R^2
A. 1982-1998								
	(1)	0.0002 (.97)			-0.014 (-3.50)			0.05
	(2)	-0.0001 (-.96)	-0.737 (-11.31)	0.453 (2.76)	-0.007 (-2.48)			0.60
	(3)	0.0002 (.79)				0.224 (2.38)		0.02
	(4)	-0.0001 (-.93)	-0.733 (-11.49)	0.433 (2.69)	-0.007 (-2.77)	0.185 (3.13)		0.62
B. May 1986-1998	(5)	0.0000 (.06)	-0.818 (-11.21)	0.420 (2.52)	-0.005 (-2.23)	0.378 (3.77)		0.68
	(6)	0.0001 (.53)					0.011 (2.89)	0.05
	(7)	0.0000 (.02)	-0.831 (-11.52)	0.326 (1.95)	-0.005 (-2.12)	0.372 (3.77)	0.006 (2.66)	0.69

much greater stability in equity required returns than is often assumed. For instance, standard application of the CAPM suggests a one-to-one change in equity returns and government bond yields.

Exhibit 6 introduces three additional proxies for risk and explores whether these variables, either individually or collectively, are correlated with the market premium. Since the estimates of implied volatility start in May 1986, the exhibit shows results for both the entire sample period and for the period during which we can introduce all variables. Entered individually each of the three variables is significantly linked to the risk premium with the coefficient having the expected sign. For instance, in regression (1) the coefficient on CON is -.014, which is significantly different from zero ($t = -3.50$). The negative coefficient signals that higher consumer confidence is linked to a lower market premium. The positive coefficients on VOL and DISP indicate the equity risk premium increases with both market volatility and disagreement among analysts. The effects of the three variables appear largely unaffected by adding other variables. For instance, in regression (4) the coefficients on CON and DISP both remain significant and are similar in magnitude to the coefficients in single variable regressions.[9]

Even in the presence of the new risk variables, Exhibit 6 shows that the market risk premium is affected by interest rate conditions. The large negative coefficient on government bond rates implies large reductions in the equity premium as interest rates rise. One feature of our data may contribute to the observed negative relationship between the market risk premium and the level of interest rates. Specifically, if analysts are slow to report updates in their growth forecasts, changes in the estimated k would not adjust fully with changes in the interest rate even if the true risk premium were constant. To address the impact of "stickiness" in the measurement of k, we formed "quarterly" measures of the risk premium that treat k as an average over the quarter. Specifically, we take the value of k at the end of a quarter and subtract from it the average value of i for the months ending when k is measured. For instance, to form the risk premium for March 1998, the average value of i for January, February, and March is subtracted from the March value of k. This approach assumes that, in March, k still reflects values of g that have not been updated from the prior two months. The quarterly measure of risk premium then is paired with the average values of the other variables for the quarter. For instance, the March 1998 "quarterly" risk premium would be paired with averaged values of BSPREAD over the January through March period. To avoid overlapping observations for the independent variables, we use only every third month (March, June, September, December) in the sample.

As reported in Exhibit 7, sensitivity analysis using "quarterly" observations suggests that delays in updating may be responsible for a portion, but not all, of the observed negative relationship between the market premium and interest rates. For example, when quarterly observations are used, the coefficient on i in regression (2) of Exhibit 7 is -.527, well below the earlier estimates but still significantly negative.[10]

As an additional test, movements in the bond risk premium (BSPREAD) are examined. Since BSPREAD is constructed directly from bond yield data, it does not have the potential for reporting lags that may affect analysts' growth forecasts. Regression 3 in Exhibit 7 shows BSPREAD is negatively linked to government rates and significantly so.[11] While the equity premium need not move in the same pattern as the corporate bond premium, the negative coefficient on BSPREAD suggests that our earlier results are not due solely to "stickiness" in measurements of market required returns.

The results in Exhibit 7 suggest that the inverse relationship between interest rates and the market risk premium may not be as pronounced as suggested in earlier exhibits. Still, there appears to be a significant negative link between the equity risk premium and government interest rates. The quarterly results in Exhibit 7 would suggest about a 50 basis point change in risk premium for each 100 basis point movement in interest rates.

Overall, the *ex ante* estimates of the market risk premium are significantly linked to *ex ante* proxies for risk. Such a link suggests that investors modify their required returns in response to perceived changes in the environment. The findings provide some comfort that our risk premium estimates are capturing, at least

[9]Realized equity returns are difficult to predict out of sample (see Goyal and Welch, 1999). Our approach is different in that we look at expectational risk premia which are much more stable. For instance, when we estimate regression coefficients (using the specification shown in regression 7 of Exhibit 6) and apply them out of sample we obtain "predictions" of expectational risk premia that are significantly more accurate (better than the .01 level) than a no change forecast. We use a "rolling regression" approach using data through December 1991 to get coefficients to predict the risk premium in January 1992. We repeat the procedure moving forward a month and dropping the oldest month of data from the regression. Details are available from the authors.

[10]Sensitivity analysis for the 1982-1989 and 1990-1998 subperiods yields results similar to those reported.

[11]We thank Bob Conroy for suggesting use of BSPREAD. Regression 3 in Exhibit 7 appears to have autocorrelated errors: the Durbin-Watson (DW) statistic rejects the hypothesis of no autocorrelation. However, in subperiod analysis, the DW statistic for the 1990-98 period is consistent with no autocorrelation and the coefficient on i is essentially the same (-.24, t = -8.05) as reported in Exhibit 7.

Exhibit 7. Regressions Using Alternate Measures of Risk Premia to Analyze Potential Effects of Reporting Lags in Analysts' Forecasts

The exhibit reports regression coefficients (t-values). Regression estimates use all variables expressed as changes (monthly or quarterly) to correct for autocorrelation. BSPREAD is the spread between yields on long-term corporate and government bonds. rp is the risk premium on the S&P500 index. The yield to maturity on long-term government bonds is denoted as i. For purposes of the regression, variables are expressed in decimal form, (e.g., 12% = .12).

Dependent Variable	Intercept	i	BSPREAD	Adj. R^2
(1) Equity Risk Premium (rp) Monthly Observations (same as Table V)	-.0002 (-1.11)	-.749 (-11.37)	.488 (2.94)	.59
(2) Equity Risk Premium (rp) "Quarterly" nonoverlapping observations to account for lags in analyst reporting	-.0002 (-.49)	-.527 (-6.18)	.550 (2.20)	.60
(3) Corporate Bond Spread (BSPREAD) Monthly Observations	-.0001 (-1.90)	-.247 (-11.29)		.38

in part, underlying changes in the economic environment. Moreover, each of the risk measures appears to contain relevant information for investors. The market risk premium is negatively related to the level of consumer confidence and positively linked to interest rate spreads between corporate and government debt, disagreement among analysts in their forecasts of earnings growth, and the implied volatility of equity returns as revealed in options data.

V. Conclusions

Shareholder required rates of return and risk premia should be based on theories about investors' expectations for the future. In practice, however, risk premia are typically estimated using averages of historical returns. This paper applies an alternate approach to estimating risk premia that employs publicly available expectational data. The resultant average market equity risk premium over government bonds is comparable in magnitude to long-term differences (1926 to 1998) in historical returns between stocks and bonds. As a result, our evidence does not resolve the equity premium puzzle; rather, the results suggest investors still expect to receive large spreads to invest in equity versus debt instruments.

There is strong evidence, however, that the market risk premium changes over time. Moreover, these changes appear linked to the level of interest rates as well as *ex ante* proxies for risk drawn from interest rate spreads in the bond market, consumer confidence in future economic conditions, disagreement among financial analysts in their forecasts and the volatility of equity returns implied by options data. The significant economic links between the market premium and a wide array of risk variables suggests that the notion of a constant risk premium over time is not an adequate explanation of pricing in equity versus debt markets.

These results have implications for practice. First, at least on average, the estimates suggest a market premium roughly comparable to long-term historical spreads in returns between stocks and bonds. Our conjecture is that, if anything, the estimates are on the high side and thus establish an upper bound on the market premium. Second, the results suggest that use of a constant risk premium will not fully capture changes in investor return requirements. As a specific example, our findings indicate that common application of models such as the CAPM will overstate changes in shareholder return requirements when government interest rates change. Rather than a one-for-one change with interest rates implied by use of constant risk premium, the results indicate that equity required returns for average risk stocks likely change by half (or less) of the change in interest rates. However, the picture is considerably more complicated as shown by the linkages between the risk premium and other attributes of risk.

Ultimately, our research does not resolve the answer to the question "What is the right market risk premium?" Perhaps more importantly, our work suggests that the answer is conditional on a number of features in the economy—not an absolute. We hope that future research will harness *ex ante* data to provide additional guidance to best practice in using a market premium to improve financial decisions.■

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Cost of Capital Estimation

The Risk Premium Approach to Measuring a Utility's Cost of Equity

Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson

Eugene F. Brigham and Dilip K. Shome are faculty members of the University of Florida and the Virginia Polytechnic Institute and State University, respectively; Steve R. Vinson is affiliated with AT&T Communications.

■ In the mid-1960s, Myron Gordon and others began applying the theory of finance to help estimate utilities' costs of capital. Previously, the standard approach in cost of equity studies was the "comparable earnings method," which involved selecting a sample of unregulated companies whose investment risk was judged to be comparable to that of the utility in question, calculating the average return on book equity (ROE) of these sample companies, and setting the utility's service rates at a level that would permit the utility to achieve the same ROE as comparable companies. This procedure has now been thoroughly discredited (see Robichek [15]), and it has been replaced by three market-oriented (as opposed to accounting-oriented) approaches: (i) the DCF method, (ii) the bond-yield-plus-risk-premium method, and (iii) the CAPM, which is a specific version of the generalized bond-yield-plus-risk-premium approach.

Our purpose in this paper is to discuss the risk-premium approach, including the market risk premium that is used in the CAPM. First, we critique the various procedures that have been used in the past to estimate risk premiums. Second, we present some data on estimated risk premiums since 1965. Third, we examine the relationship between equity risk premiums and the level of interest rates, because it is important, for purposes of estimating the cost of capital, to know just how stable the relationship between risk premiums and interest rates is over time. If stability exists, then one can estimate the cost of equity at any point in time as a function of interest rates as reported in *The Wall Street Journal*, the *Federal Reserve Bulletin*, or some similar source.[1] Fourth, while we do not discuss the CAPM directly, our analysis does have some important implications for selecting a market risk premium for use in that model. Our focus is on utilities, but the methodology is applicable to the estimation of the cost of

[1]For example, the Federal Energy Regulatory Commission's Staff recently proposed that a risk premium be estimated every two years and that, between estimation dates, the last-determined risk premium be added to the current yield on ten-year Treasury bonds to obtain an estimate of the cost of equity to an average utility (Docket RM 80-36). Subsequently, the FCC made a similar proposal ("Notice of Proposed Rulemaking," August 13, 1984, Docket No. 84-800). Obviously, the validity of such procedures depends on (i) the accuracy of the risk premium estimate and (ii) the stability of the relationship between risk premiums and interest rates. Both proposals are still under review.

equity for any publicly traded firm, and also for non-traded firms for which an appropriate risk class can be assessed, including divisions of publicly traded corporations.[2]

Alternative Procedures for Estimating Risk Premiums

In a review of both rate cases and the academic literature, we have identified three basic methods for estimating equity risk premiums: (i) the *ex post*, or historic, yield spread method; (ii) the survey method; and (iii) an *ex ante* yield spread method based on DCF analysis.[3] In this section, we briefly review these three methods.

Historic Risk Premiums

A number of researchers, most notably Ibbotson and Sinquefield [12], have calculated historic holding period returns on different securities and then estimated risk premiums as follows:

$$\text{Historic Risk Premium} = \begin{pmatrix}\text{Average of the}\\ \text{annual returns on}\\ \text{a stock index for}\\ \text{a particular}\\ \text{past period}\end{pmatrix} - \begin{pmatrix}\text{Average of the}\\ \text{annual returns on}\\ \text{a bond index for}\\ \text{the same}\\ \text{past period}\end{pmatrix}. \quad (1)$$

Ibbotson and Sinquefield (I&S) calculated both arithmetic and geometric average returns, but most of their risk-premium discussion was in terms of the geometric averages. Also, they used both corporate and Treasury bond indices, as well as a T-bill index, and they analyzed all possible holding periods since 1926. The I&S study has been employed in numerous rate cases in two ways: (i) directly, where the I&S historic risk premium is added to a company's bond yield to obtain an estimate of its cost of equity, and (ii) indirectly, where I&S data are used to estimate the market risk premium in CAPM studies.

There are both conceptual and measurement problems with using I&S data for purposes of estimating the cost of capital. Conceptually, there is no compelling reason to think that investors expect the same relative returns that were earned in the past. Indeed, evidence presented in the following sections indicates that relative expected returns should, and do, vary significantly over time. Empirically, the measured historic premium is sensitive both to the choice of estimation horizon and to the end points. These choices are essentially arbitrary, yet they can result in significant differences in the final outcome. These measurement problems are common to most forecasts based on time series data.

The Survey Approach

One obvious way to estimate equity risk premiums is to poll investors. Charles Benore [1], the senior utility analyst for Paine Webber Mitchell Hutchins, a leading institutional brokerage house, conducts such a survey of major institutional investors annually. His 1983 results are reported in Exhibit 1.

Exhibit 1. Results of Risk Premium Survey, 1983*

Assuming a double A, long-term utility bond currently yields 12½%, the common stock for the same company would be fairly priced relative to the bond if its expected return was as follows:

Total Return	Indicated Risk Premium (basis points)	Percent of Respondents
over 20½%	over 800	
20½%	800	
19½%	700	
18½%	600	10%
17½%	500	8%
16½%	400	29%
15½%	300	35%
14½%	200	16%
13½%	100	0%
under 13½%	under 100	1%
Weighted average	358	100%

*Benore's questionnaire included the first two columns, while his third column provided a space for the respondents to indicate which risk premium they thought applied. We summarized Benore's responses in the frequency distribution given in Column 3. Also, in his questionnaire each year, Benore adjusts the double A bond yield and the total returns (Column 1) to reflect current market conditions. Both the question above and the responses to it were taken from the survey conducted in April 1983.

[2]The FCC is particularly interested in risk-premium methodologies, because (i) only eighteen of the 1,400 telephone companies it regulates have publicly-traded stock, and hence offer the possibility of DCF analysis, and (ii) most of the publicly-traded telephone companies have both regulated and unregulated assets, so a corporate DCF cost might not be applicable to the regulated units of the companies.

[3]In rate cases, some witnesses also have calculated the differential between the yield to maturity (YTM) of a company's bonds and its concurrent ROE, and then called this differential a risk premium. In general, this procedure is unsound, because the YTM on a bond is a *future expected* return on the bond's *market value*, while the ROE is the *past realized* return on the stock's *book value*. Thus, comparing YTMs and ROEs is like comparing apples and oranges.

Benore's results, as measured by the average risk premiums, have varied over the years as follows:

Year	Average RP (basis points)
1978	491
1979	475
1980	423
1981	349
1982	275
1983	358

The survey approach is conceptually sound in that it attempts to measure investors' expectations regarding risk premiums, and the Benore data also seem to be carefully collected and processed. Therefore, the Benore studies do provide one useful basis for estimating risk premiums. However, as with most survey results, the possibility of biased responses and/or biased sampling always exists. For example, if the responding institutions are owners of utility stocks (and many of them are), and if the respondents think that the survey results might be used in a rate case, then they might bias upward their responses to help utilities obtain higher authorized returns. Also, Benore surveys large institutional investors, whereas a high percentage of utility stocks are owned by individuals rather than institutions, so there is a question as to whether his reported risk premiums are really based on the expectations of the "representative" investor. Finally, from a pragmatic standpoint, there is a question as to how to use the Benore data for utilities that are not rated AA. The Benore premiums can be applied as an add-on to the own-company bond yields of any given utility only if it can be assumed that the premiums are constant across bond rating classes. *A priori*, there is no reason to believe that the premiums will be constant.

DCF-Based *Ex Ante* Risk Premiums

In a number of studies, the DCF model has been used to estimate the *ex ante* market risk premium, RP_M. Here, one estimates the average expected future return on equity for a group of stocks, k_M, and then subtracts the concurrent risk-free rate, R_F, as proxied by the yield to maturity on either corporate or Treasury securities:[4]

$$RP_M = k_M - R_F. \qquad (2)$$

Conceptually, this procedure is exactly like the I&S approach except that one makes direct estimates of future expected returns on stocks and bonds rather than assuming that investors expect future returns to mirror past returns.

The most difficult task, of course, is to obtain a valid estimate of k_M, the expected rate of return on the market. Several studies have attempted to estimate DCF risk premiums for the utility industry and for other stock market indices. Two of these are summarized next.

Vandell and Kester. In a recently published monograph, Vandell and Kester [18] estimated *ex ante* risk premiums for the period from 1944 to 1978. R_F was measured both by the yield on 90-day T-bills and by the yield on the Standard and Poor's AA Utility Bond Index. They measured k_M as the average expected return on the S&P's 500 Index, with the expected return on individual securities estimated as follows:

$$k_i = \left(\frac{D_1}{P_0}\right)_i + g_i, \qquad (3)$$

where,

D_1 = dividend per share expected over the next twelve months,
P_0 = current stock price,
g = estimated long-term constant growth rate, and
i = the i^{th} stock.

To estimate g_i, Vandell and Kester developed fifteen forecasting modéls based on both exponential smoothing and trend-line forecasts of earnings and dividends, and they used historic data over several estimating horizons. Vandell and Kester themselves acknowledge that, like the Ibbotson-Sinquefield premiums, their analysis is subject to potential errors associated with trying to estimate expected future growth purely from past data. We shall have more to say about this point later.

[4]In this analysis, most people have used yields on long-term bonds rather than short-term money market instruments. It is recognized that long-term bonds, even Treasury bonds, are not risk free, so an RP_M based on these debt instruments is smaller than it would be if there were some better proxy to the long-term riskless rate. People have attempted to use the T-bill rate for R_F, but the T-bill rate embodies a different average inflation premium than stocks, and it is subject to random fluctuations caused by monetary policy, international currency flows, and other factors. Thus, many people believe that for cost of capital purposes, R_F should be based on long-term securities.

We did test to see how debt maturities would affect our calculated risk premiums. If a short-term rate such as the 30-day T-bill rate is used, measured risk premiums jump around widely and, so far as we could tell, randomly. The choice of a maturity in the 10- to 30-year range has little effect, as the yield curve is generally fairly flat in that range.

Malkiel. Malkiel [14] estimated equity risk premiums for the Dow Jones Industrials using the DCF model. Recognizing that the constant dividend growth assumption may not be valid, Malkiel used a nonconstant version of the DCF model. Also, rather than rely exclusively on historic data, he based his growth rates on Value Line's five-year earnings growth forecasts plus the assumption that each company's growth rate would, after an initial five-year period, move toward a long-run real national growth rate of four percent. He also used ten-year maturity government bonds as a proxy for the riskless rate. Malkiel reported that he tested the sensitivity of his results against a number of different types of growth rates, but, in his words, "The results are remarkably robust, and the estimated risk premiums are all very similar." Malkiel's is, to the best of our knowledge, the first risk-premium study that uses analysts' forecasts. A discussion of analysts' forecasts follows.

Security Analysts' Growth Forecasts

Ex ante DCF risk premium estimates can be based either on expected growth rates developed from time series data, such as Vandell and Kester used, or on analysts' forecasts, such as Malkiel used. Although there is nothing inherently wrong with time series-based growth rates, an increasing body of evidence suggests that primary reliance should be placed on analysts' growth rates. First, we note that the observed market price of a stock reflects the consensus view of investors regarding its future growth. Second, we know that most large brokerage houses, the larger institutional investors, and many investment advisory organizations employ security analysts who forecast future EPS and DPS, and, to the extent that investors rely on analysts' forecasts, the consensus of analysts' forecasts is embodied in market prices. Third, there have been literally dozens of academic research papers dealing with the accuracy of analysts' forecasts, as well as with the extent to which investors actually use them. For example, Cragg and Malkiel [7] and Brown and Rozeff [5] determined that security analysts' forecasts are more relevant in valuing common stocks and estimating the cost of capital than are forecasts based solely on historic time series. Stanley, Lewellen, and Schlarbaum [16] and Linke [13] investigated the importance of analysts' forecasts and recommendations to the investment decisions of individual and institutional investors. Both studies indicate that investors rely heavily on analysts' reports and incorporate analysts' forecast information in the formation of their expectations about stock returns. A representative listing of other work supporting the use of analysts' forecasts is included in the References section. Thus, evidence in the current literature indicates that (i) analysts' forecasts are superior to forecasts based solely on time series data, and (ii) investors do rely on analysts' forecasts. Accordingly, we based our cost of equity, and hence risk premium estimates, on analysts' forecast data.[5]

Risk Premium Estimates

For purposes of estimating the cost of capital using the risk premium approach, it is necessary either that the risk premiums be time-invariant or that there exists a predictable relationship between risk premiums and interest rates. If the premiums are constant over time, then the constant premium could be added to the prevailing interest rate. Alternatively, if there exists a stable relationship between risk premiums and interest rates, it could be used to predict the risk premium from the prevailing interest rate.

To test for stability, we obviously need to calculate risk premiums over a fairly long period of time. Prior to 1980, the only consistent set of data we could find came from Value Line, and, because of the work involved, we could develop risk premiums only once a year (on January 1). Beginning in 1980, however, we began collecting and analyzing Value Line data on a monthly basis, and in 1981 we added monthly estimates from Merrill Lynch and Salomon Brothers to our data base. Finally, in mid-1983, we expanded our analysis to include the IBES data.

Annual Data and Results, 1966–1984

Over the period 1966–1984, we used Value Line data to estimate risk premiums both for the electric utility industry and for industrial companies, using the companies included in the Dow Jones Industrial and Utility averages as representative of the two groups. Value Line makes a five-year growth rate forecast, but it also gives data from which one can develop a longer-term forecast. Since DCF theory calls for a truly long-term (infinite horizon) growth rate, we concluded that it was better to develop and use such a forecast than to

[5]Recently, a new type of service that summarizes the key data from most analysts' reports has become available. We are aware of two sources of such services, the Lynch, Jones, and Ryan's Institutional Brokers Estimate System (IBES) and Zack's Icarus Investment Service. IBES and the Icarus Service gather data from both buy-side and sell-side analysts and provide it to subscribers on a monthly basis in both a printed and a computer-readable format.

Exhibit 2. Estimated Annual Risk Premiums, Nonconstant (Value Line) Model, 1966–1984

January 1 of the Year Reported	Dow Jones Electrics			Dow Jones Industrials			
	k_{Avg}	R_F	RP	k_{Avg}	R_F	RP	(3) ÷ (6)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1966	8.11%	4.50%	3.61%	9.56%	4.50%	5.06%	0.71
1967	9.00%	4.76%	4.24%	11.57%	4.76%	6.81%	0.62
1968	9.68%	5.59%	4.09%	10.56%	5.59%	4.97%	0.82
1969	9.34%	5.88%	3.46%	10.96%	5.88%	5.08%	0.68
1970	11.04%	6.91%	4.13%	12.22%	6.91%	5.31%	0.78
1971	10.80%	6.28%	4.52%	11.23%	6.28%	4.95%	0.91
1972	10.53%	6.00%	4.53%	11.09%	6.00%	5.09%	0.89
1973	11.37%	5.96%	5.41%	11.47%	5.96%	5.51%	0.98
1974	13.85%	7.29%	6.56%	12.38%	7.29%	5.09%	1.29
1975	16.63%	7.91%	8.72%	14.83%	7.91%	6.92%	1.26
1976	13.97%	8.23%	5.74%	13.32%	8.23%	5.09%	1.13
1977	12.96%	7.30%	5.66%	13.63%	7.30%	6.33%	0.89
1978	13.42%	7.87%	5.55%	14.75%	7.87%	6.88%	0.81
1979	14.92%	8.99%	5.93%	15.50%	8.99%	6.51%	0.91
1980	16.39%	10.18%	6.21%	16.53%	10.18%	6.35%	0.98
1981	17.61%	11.99%	5.62%	17.37%	11.99%	5.38%	1.04
1982	17.70%	14.00%	3.70%	19.30%	14.00%	5.30%	0.70
1983	16.30%	10.66%	5.64%	16.53%	10.66%	5.87%	0.96
1984	16.03%	11.97%	4.06%	15.72%	11.97%	3.75%	1.08

use the five-year prediction.[6] Therefore, we obtained data as of January 1 from Value Line for each of the Dow Jones companies and then solved for k, the expected rate of return, in the following equation:

$$P_0 = \sum_{t=1}^{n} \frac{D_t}{(1 + k)^t} + \left(\frac{D_n(1 + g_n)}{k - g_n}\right)\left(\frac{1}{1 + k}\right)^n. \quad (4)$$

Equation (4) is the standard nonconstant growth DCF model; P_0 is the current stock price; D_t represents the forecasted dividends during the nonconstant growth period; n is the years of nonconstant growth; D_n is the first constant growth dividend; and g_n is the constant, long-run growth rate after year n. Value Line provides D_t values for $t = 1$ and $t = 4$, and we interpolated to obtain D_2 and D_3. Value Line also gives estimates for ROE and for the retention rate (b) in the terminal year, n, so we can forecast the long-term growth rate as $g_n = b(ROE)$. With all the values in Equation (4) specified except k, we can solve for k, which is the DCF rate of return that would result if the Value Line forecasts were met, and, hence, the DCF rate of return implied in the Value Line forecast.[7]

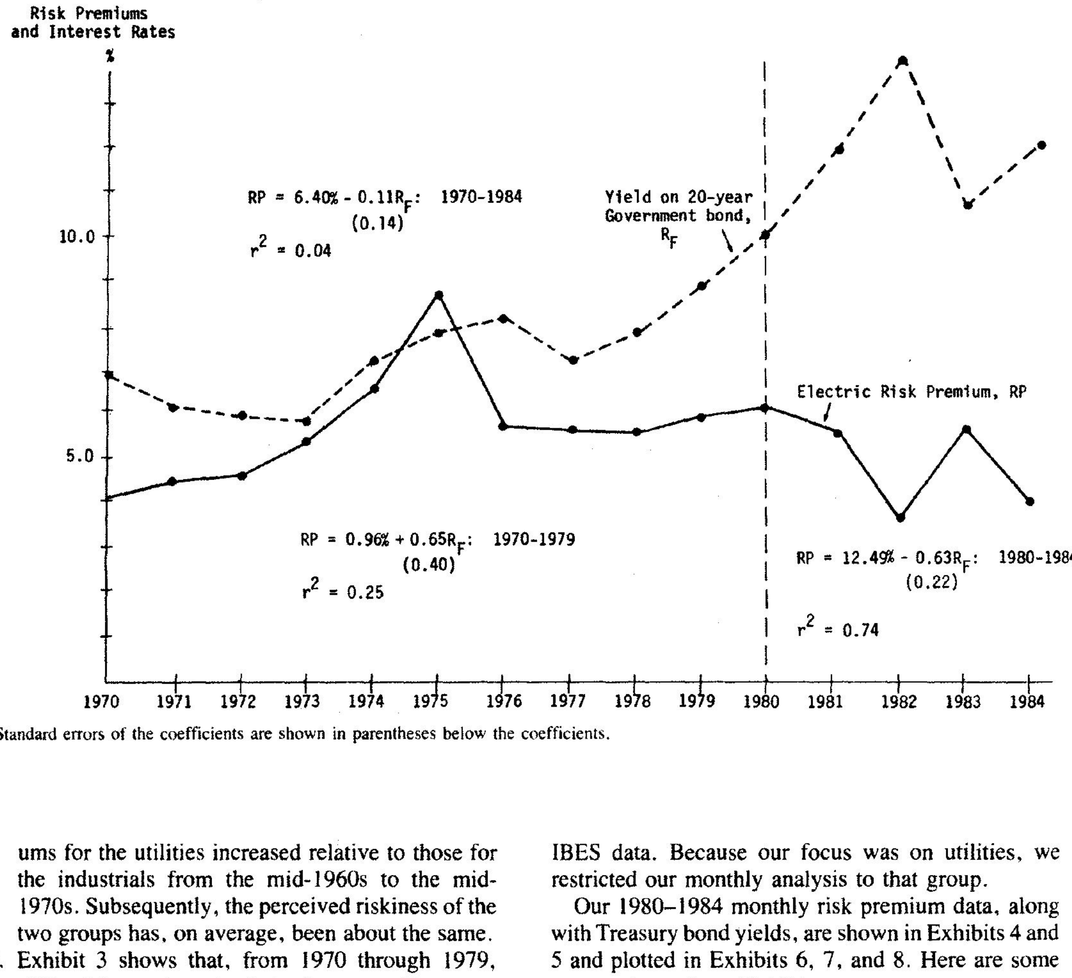
Having estimated a k value for each of the electric and industrial companies, we averaged them (using market-value weights) to obtain a k value for each group, after which we subtracted R_F (taken as the December 31 yield on twenty-year constant maturity Treasury bonds) to obtain the estimated risk premiums shown in Exhibit 2. The premiums for the electrics are plotted in Exhibit 3, along with interest rates. The following points are worthy of note:

1. Risk premiums fluctuate over time. As we shall see in the next section, fluctuations are even wider when measured on a monthly basis.
2. The last column of Exhibit 2 shows that risk premi-

[6]This is a debatable point. Cragg and Malkiel, as well as many practicing analysts, feel that most investors actually focus on five-year forecasts. Others, however, argue that five-year forecasts are too heavily influenced by base-year conditions and/or other nonpermanent conditions for use in the DCF model. We note (i) that most published forecasts do indeed cover five years, (ii) that such forecasts are typically "normalized" in some fashion to alleviate the base-year problem, and (iii) that for relatively stable companies like those in the Dow Jones averages, it generally does not matter greatly if one uses a normalized five-year or a longer-term forecast, because these companies meet the conditions of the constant-growth DCF model rather well.

[7]Value Line actually makes an explicit price forecast for each stock, and one could use this price, along with the forecasted dividends, to develop an expected rate of return. However, Value Line's forecasted stock price builds in a forecasted *change* in k. Therefore, the forecasted price is inappropriate for use in estimating current values of k.

Exhibit 3. Equity Risk Premiums for Electric Utilities and Yields on 20-Year Government Bonds, 1970–1984*



*Standard errors of the coefficients are shown in parentheses below the coefficients.

ums for the utilities increased relative to those for the industrials from the mid-1960s to the mid-1970s. Subsequently, the perceived riskiness of the two groups has, on average, been about the same.

3. Exhibit 3 shows that, from 1970 through 1979, utility risk premiums tended to have a positive association with interest rates: when interest rates rose, so did risk premiums, and vice versa. However, beginning in 1980, an inverse relationship appeared: rising interest rates led to declining risk premiums. We shall discuss this situation further in the next section.

Monthly Data and Results, 1980–1984

In early 1980, we began calculating risk premiums on a monthly basis. At that time, our only source of analysts' forecasts was Value Line, but beginning in 1981 we also obtained Merrill Lynch and Salomon Brothers' data, and then, in mid-1983, we obtained IBES data. Because our focus was on utilities, we restricted our monthly analysis to that group.

Our 1980–1984 monthly risk premium data, along with Treasury bond yields, are shown in Exhibits 4 and 5 and plotted in Exhibits 6, 7, and 8. Here are some comments on these Exhibits:

1. Risk premiums, like interest rates and stock prices, are volatile. Our data indicate that it would not be appropriate to estimate the cost of equity by adding the current cost of debt to a risk premium that had been estimated in the past. Current risk premiums should be matched with current interest rates.
2. Exhibit 6 confirms the 1980–1984 section of Exhibit 3 in that it shows a strong inverse relationship between interest rates and risk premiums; we shall discuss shortly why this relationship holds.
3. Exhibit 7 shows that while risk premiums based on Value Line, Merrill Lynch, and Salomon Brothers

Exhibit 4. Estimated Monthly Risk Premiums for Electric Utilities Using Analysts' Growth Forecasts, January 1980–June 1984

Beginning of Month	Value Line	Merrill Lynch	Salomon Brothers	Average Premiums	20-Year Treasury Bond Yield, Constant Maturity Series
Jan 1980	6.21%	NA	NA	6.21%	10.18%
Feb 1980	5.77%	NA	NA	5.77%	10.86%
Mar 1980	4.73%	NA	NA	4.73%	12.59%
Apr 1980	5.02%	NA	NA	5.02%	12.71%
May 1980	4.73%	NA	NA	4.73%	11.04%
Jun 1980	5.09%	NA	NA	5.09%	10.37%
Jul 1980	5.41%	NA	NA	5.41%	9.86%
Aug 1980	5.72%	NA	NA	5.72%	10.29%
Sep 1980	5.16%	NA	NA	5.16%	11.41%
Oct 1980	5.62%	NA	NA	5.62%	11.75%
Nov 1980	5.09%	NA	NA	5.09%	12.33%
Dec 1980	5.65%	NA	NA	5.65%	12.37%
Annual Avg.	5.35%			5.35%	11.31%
Jan 1981	5.62%	4.76%	5.63%	5.34%	11.99%
Feb 1981	4.82%	4.87%	5.16%	4.95%	12.48%
Mar 1981	4.70%	3.73%	4.97%	4.47%	13.10%
Apr 1981	4.24%	3.23%	4.52%	4.00%	13.11%
May 1981	3.54%	3.24%	4.24%	3.67%	13.51%
Jun 1981	3.57%	4.04%	4.27%	3.96%	13.39%
Jul 1981	3.61%	3.63%	4.16%	3.80%	13.32%
Aug 1981	3.17%	3.05%	3.04%	3.09%	14.23%
Sep 1981	2.11%	2.24%	2.35%	2.23%	14.99%
Oct 1981	2.83%	2.64%	3.24%	2.90%	14.93%
Nov 1981	2.08%	2.49%	3.03%	2.53%	15.27%
Dec 1981	3.72%	3.45%	4.24%	3.80%	13.12%
Annual Avg.	3.67%	3.45%	4.07%	3.73%	13.62%
Jan 1982	3.70%	3.37%	4.04%	3.70%	14.00%
Feb 1982	3.05%	3.37%	3.70%	3.37%	14.37%
Mar 1982	3.15%	3.28%	3.75%	3.39%	13.96%

Beginning of Month	Value Line	Merrill Lynch	Salomon Brothers	Average Premiums	20-Year Treasury Bond Yield, Constant Maturity Series
Apr 1982	3.49%	3.61%	4.29%	3.80%	13.69%
May 1982	3.08%	4.25%	3.91%	3.75%	13.47%
Jun 1982	3.16%	4.51%	4.72%	4.13%	13.53%
Jul 1982	2.57%	4.21%	4.21%	3.66%	14.48%
Aug 1982	4.33%	4.83%	5.27%	4.81%	13.69%
Sep 1982	4.08%	5.14%	5.58%	4.93%	12.40%
Oct 1982	5.35%	5.24%	6.34%	5.64%	11.95%
Nov 1982	5.67%	5.95%	6.91%	6.18%	10.97%
Dec 1982	6.31%	6.71%	7.45%	6.82%	10.52%
Annual Avg.	4.00%	4.54%	5.01%	4.52%	13.09%
Jan 1983	5.64%	6.04%	6.81%	6.16%	10.66%
Feb 1983	4.68%	5.99%	6.10%	5.59%	11.01%
Mar 1983	4.99%	6.89%	6.43%	6.10%	10.71%
Apr 1983	4.75%	5.82%	6.31%	5.63%	10.84%
May 1983	4.50%	6.41%	6.24%	5.72%	10.57%
Jun 1983	4.29%	5.21%	6.16%	5.22%	10.90%
Jul 1983	4.78%	5.72%	6.42%	5.64%	11.12%
Aug 1983	3.89%	4.74%	5.41%	4.68%	11.78%
Sep 1983	4.07%	4.90%	5.57%	4.85%	11.71%
Oct 1983	3.79%	4.64%	5.38%	4.60%	11.64%
Nov 1983	2.84%	3.77%	4.46%	3.69%	11.90%
Dec 1983	3.36%	4.27%	5.00%	4.21%	11.83%
Annual Avg.	4.30%	5.37%	5.86%	5.17%	11.22%
Jan 1984	4.06%	5.04%	5.65%	4.92%	11.97%
Feb 1984	4.25%	5.37%	5.96%	5.19%	11.76%
Mar 1984	4.73%	6.05%	6.38%	5.72%	12.12%
Apr 1984	4.78%	5.33%	6.32%	5.48%	12.51%
May 1984	4.36%	5.30%	6.42%	5.36%	12.78%
Jun 1984	3.54%	4.00%	5.63%	4.39%	13.60%

Exhibit 5. Monthly Risk Premiums Based on IBES Data

Beginning of Month	Average of Merrill Lynch, Salomon Brothers, and Value Line Premiums for Dow Jones Electrics	IBES Premiums for Dow Jones Electrics	IBES Premiums for Entire Electric Industry
Aug 1983	4.68%	4.10%	4.16%
Sep 1983	4.85%	4.43%	4.27%
Oct 1983	4.60%	4.31%	3.90%
Nov 1983	3.69%	3.36%	3.36%
Dec 1983	4.21%	3.86%	3.54%
Jan 1984	4.92%	4.68%	4.18%

Beginning of Month	Average of Merrill Lynch, Salomon Brothers, and Value Line Premiums for Dow Jones Electrics	IBES Premiums for Dow Jones Electrics	IBES Premiums for Entire Electric Industry
Feb 1984	5.19%	5.00%	4.36%
Mar 1984	5.72%	5.35%	4.45%
Apr 1984	5.48%	5.33%	4.23%
May 1984	5.36%	5.26%	4.30%
Jun 1984	4.39%	4.47%	3.40%
Average Premiums	4.83%	4.56%	4.01%

Exhibit 6. Utility Risk Premiums and Interest Rates, 1980–1984

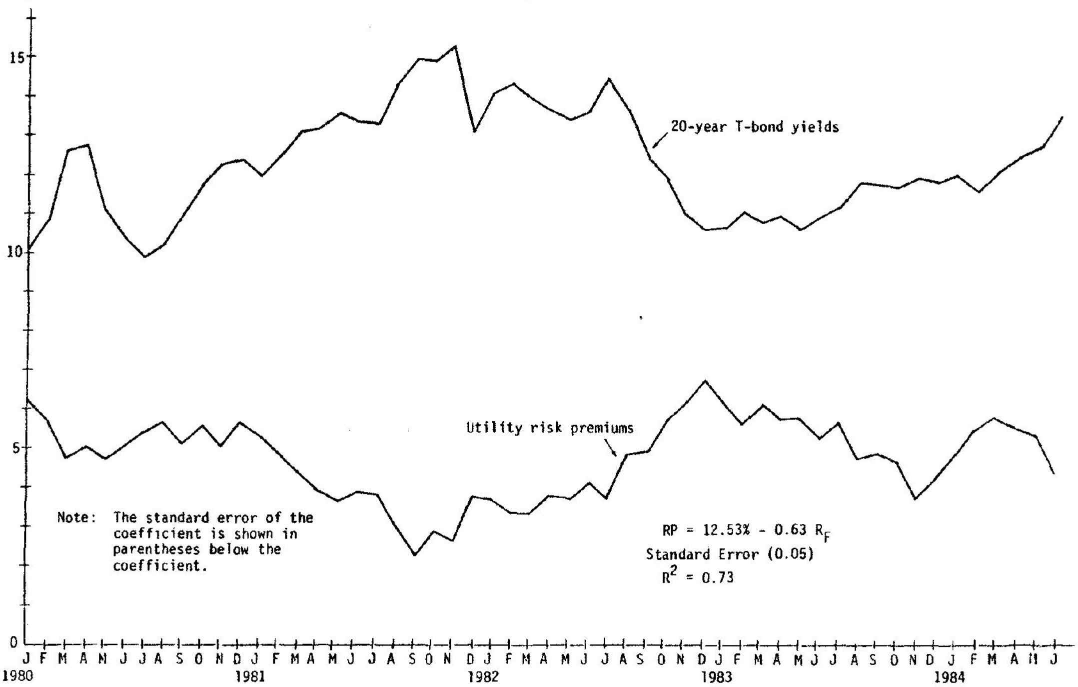


Exhibit 7. Monthly Risk Premiums, Electric Utilities, 1981–1984 (to Date)

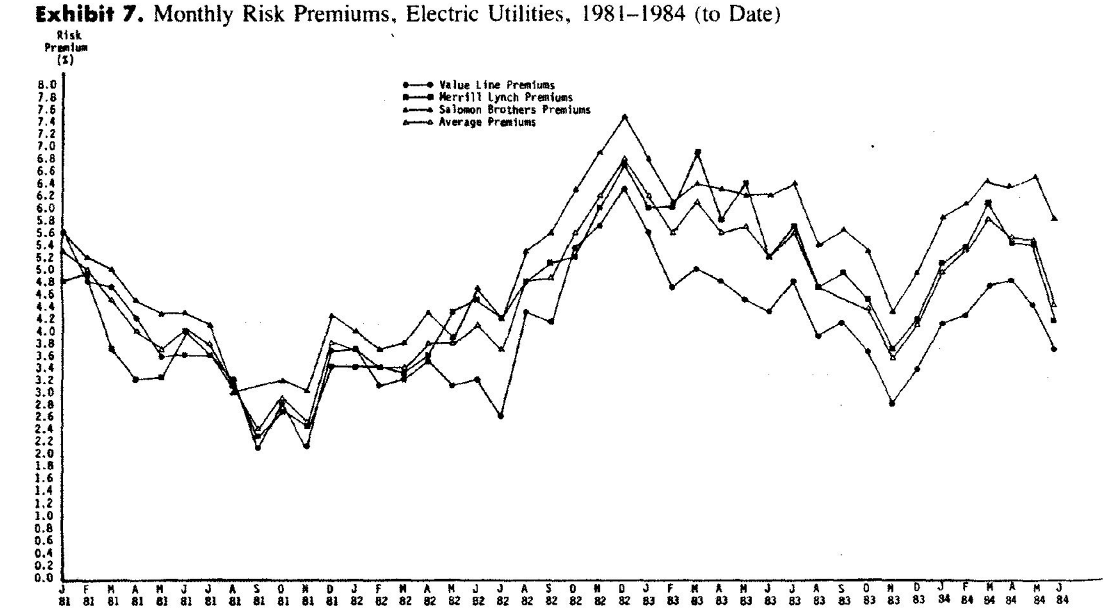
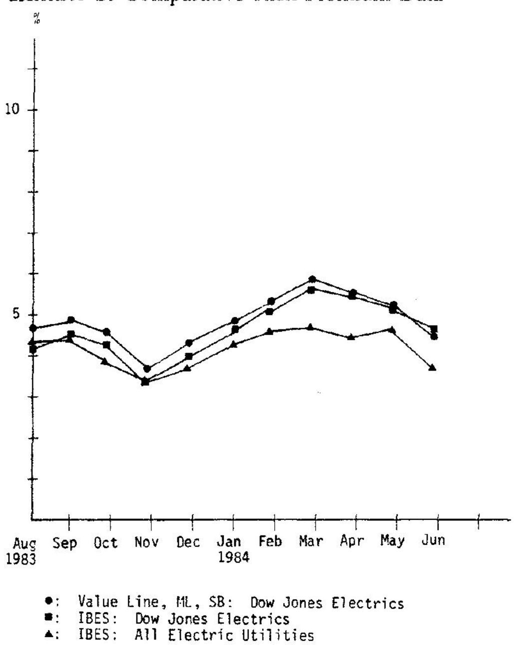


Exhibit 8. Comparative Risk Premium Data



do differ, the differences are not large given the nature of the estimates, and the premiums follow one another closely over time. Since all of the analysts are examining essentially the same data and since utility companies are not competitive with one another, and hence have relatively few secrets, the similarity among the analysts' forecasts is not surprising.

4. The IBES data, presented in Exhibit 5 and plotted in Exhibit 8, contain too few observations to enable us to draw strong conclusions, but (i) the Dow Jones Electrics risk premiums based on our three-analyst data have averaged 27 basis points above premiums based on the larger group of analysts surveyed by IBES and (ii) the premiums on the 11 Dow Jones Electrics have averaged 54 basis points higher than premiums for the entire utility industry followed by IBES. Given the variability in the data, we are, at this point, inclined to attribute these differences to random fluctuations, but as more data become available, it may turn out that the differences are statistically significant. In particular, the 11 electric utilities included in the Dow Jones Utility Index all have large nuclear investments, and this may cause them to be regarded as riskier than the industry average, which includes both nuclear and non-nuclear companies.

Tests of the Reasonableness of the Risk Premium Estimates

So far our claims to the reasonableness of our risk-premium estimates have been based on the reasonableness of our variable measures, particularly the measures of expected dividend growth rates. Essentially, we have argued that since there is strong evidence in the literature in support of analysts' forecasts, risk premiums based on these forecasts are reasonable. In the spirit of positive economics, however, it is also important to demonstrate the reasonableness of our results more directly.

It is theoretically possible to test for the validity of the risk-premium estimates in a CAPM framework. In a cross-sectional estimate of the CAPM equation,

$$(k - R_F)_i = \alpha_0 + \alpha_1\beta_i + u_i, \qquad (5)$$

we would expect

$$\hat{\alpha}_0 = 0 \text{ and } \hat{\alpha}_1 = k_M - R_F = \text{Market risk premium.}$$

This test, of course, would be a joint test of both the CAPM and the reasonableness of our risk-premium estimates. There is a great deal of evidence that questions the empirical validity of the CAPM, especially when applied to regulated utilities. Under these conditions, it is obvious that no unambiguous conclusion can be drawn regarding the efficacy of the premium estimates from such a test.[8]

A simpler and less ambiguous test is to show that the risk premiums are higher for lower rated firms than for higher rated firms. Using 1984 data, we classified the

[8]We carried out the test on a monthly basis for 1984 and found positive but statistically insignificant coefficients. A typical result (for April 1984) follows:

$$(k - R_F)_i = \underset{(0.91)}{3.1675} + \underset{(1.44)}{1.8031}\ \beta_i.$$

The figures in parentheses are standard errors. Utility risk premiums do increase with betas, but the intercept term is not zero as the CAPM would predict, and α_1 is both less than the predicted value and not statistically significant. Again, the observation that the coefficients do not conform to CAPM predictions could be as much a problem with CAPM specification for utilities as with the risk premium estimates.

A similar test was carried out by Friend, Westerfield, and Granito [9]. They tested the CAPM using expectational (survey) data rather than *ex post* holding period returns. They actually found their coefficient of β_i to be negative in all their cross-sectional tests.

Exhibit 9. Relationship between Risk Premiums and Bond Ratings, 1984*

Month	Aaa/AA	AA	Aa/A	A	A/BBB	BBB	Below BBB
January†	—	2.61%	3.06%	3.70%	5.07%	4.90%	9.45%
February	2.98%	3.17%	3.36%	4.03%	5.26%	5.14%	7.97%
March	2.34%	3.46%	3.29%	4.06%	5.43%	5.02%	8.28%
April	2.37%	3.03%	3.29%	3.88%	5.29%	4.97%	6.96%
May	2.00%	2.48%	3.42%	3.72%	4.72%	6.64%	8.81%
June	0.72%	2.17%	2.46%	3.16%	3.76%	5.00%	5.58%
Average	2.08%	2.82%	3.15%	3.76%	4.92%	5.28%	7.84%

*The risk premiums are based on IBES data for the electric utilities followed by both IBES and Salomon Brothers. The number of electric utilities followed by both firms varies from month to month. For the period between January and June 1984, the number of electrics followed by both firms ranged from 96 to 99 utilities.
†In January, there were no Aaa/AA companies. Subsequently, four utilities were upgraded to Aaa/AA.

utility industry into risk groups based on bond ratings. For each rating group, we estimated the average risk premium. The results, presented in Exhibit 9, clearly show that the lower the bond rating, the higher the risk premiums. Our premium estimates therefore would appear to pass this simple test of reasonableness.

Risk Premiums and Interest Rates

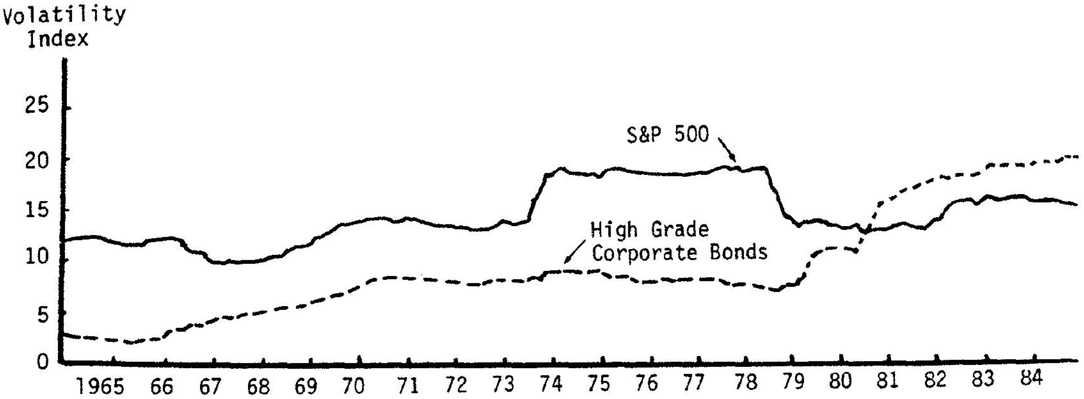
Traditionally, stocks have been regarded as being riskier than bonds because bondholders have a prior claim on earnings and assets. That is, stockholders stand at the end of the line and receive income and/or assets only after the claims of bondholders have been satisfied. However, if interest rates fluctuate, then the holders of long-term bonds can suffer losses (either realized or in an opportunity cost sense) even though they receive all contractually due payments. Therefore, if investors' worries about "interest rate risk" versus "earning power risk" vary over time, then perceived risk differentials between stocks and bonds, and hence risk premiums, will also vary.

Any number of events could occur to cause the perceived riskiness of stocks versus bonds to change, but probably the most pervasive factor, over the 1966–1984 period, is related to inflation. Inflationary expectations are, of course, reflected in interest rates. Therefore, one might expect to find a relationship between risk premiums and interest rates. As we noted in our discussion of Exhibit 3, risk premiums were positively correlated with interest rates from 1966 through 1979, but, beginning in 1980, the relationship turned negative. A possible explanation for this change is given next.

1966–1979 Period. During this period, inflation heated up, fuel prices soared, environmental problems surfaced, and demand for electricity slowed even as expensive new generating units were nearing completion. These cost increases required offsetting rate hikes to maintain profit levels. However, political pressure, combined with administrative procedures that were not designed to deal with a volatile economic environment, led to long periods of "regulatory lag" that caused utilities' earned ROEs to decline in absolute terms and to fall far below the cost of equity. These factors combined to cause utility stockholders to experience huge losses: S&P's Electric Index dropped from a mid-1960s high of 60.90 to a mid-1970s low of 20.41, a decrease of 66.5%. Industrial stocks also suffered losses during this period, but, on average, they were only one third as severe as the utilities' losses. Similarly, investors in long-term bonds had losses, but bond losses were less than half those of utility stocks. Note also that, during this period, (i) bond investors were able to reinvest coupons and maturity payments at rising rates, whereas the earned returns on equity did not rise, and (ii) utilities were providing a rising share of their operating income to debtholders versus stockholders (interest expense/book value of debt was rising, while net income/common equity was declining). This led to a widespread belief that utility commissions would provide enough revenues to keep utilities from going bankrupt (barring a disaster), and hence to protect the bondholders, but that they would not necessarily provide enough revenues either to permit the expected rate of dividend growth to occur or, perhaps, even to allow the dividend to be maintained.

Because of these experiences, investors came to regard inflation as having a more negative effect on utility stocks than on bonds. Therefore, when fears of inflation increased, utilities' measured risk premiums

Exhibit 10. Relative Volatility* of Stocks and Bonds, 1965–1984



*Volatility is measured as the standard deviation of total returns over the last 5 years.
Source: Merrill Lynch, *Quantitative Analysis*, May/June 1984.

also increased. A regression over the period 1966–1979, using our Exhibit 2 data, produced this result:

$$RP = 0.30\% + \underset{(0.22)}{0.73}\, R_F; \qquad r^2 = 0.48.$$

This indicates that a one percentage point increase in the Treasury bond rate produced, on average, a 0.73 percentage point increase in the risk premium, and hence a 1.00 + 0.73 = 1.73 percentage point increase in the cost of equity for utilities.

1980–1984 Period. The situation changed dramatically in 1980 and thereafter. Except for a few companies with nuclear construction problems, the utilities' financial situations stabilized in the early 1980s, and then improved significantly from 1982 to 1984. Both the companies and their regulators were learning to live with inflation; many construction programs were completed; regulatory lags were shortened; and in general the situation was much better for utility equity investors. In the meantime, over most of the 1980–1984 period, interest rates and bond prices fluctuated violently, both in an absolute sense and relative to common stocks. Exhibit 10 shows the volatility of corporate bonds very clearly. Over most of the eighteen-year period, stock returns were much more volatile than returns on bonds. However, that situation changed in October 1979, when the Fed began to focus on the money supply rather than on interest rates.[9]

In the 1980–1984 period, an increase in inflationary expectations has had a more adverse effect on bonds than on utility stocks. If the expected rate of inflation increases, then interest rates *will increase* and bond prices *will fall*. Thus, uncertainty about inflation translates directly into risk in the bond markets. The effect of inflation on stocks, including utility stocks, is less clear. If inflation increases, then utilities should, in theory, be able to obtain rate increases that would offset increases in operating costs and also compensate for the higher cost of equity. Thus, with "proper" regulation, utility stocks would provide a better hedge against unanticipated inflation than would bonds. This hedge did not work at all well during the 1966–1979 period, because inflation-induced increases in operating and capital costs were not offset by timely rate increases. However, as noted earlier, both the utilities and their regulators seem to have learned to live better with inflation during the 1980s.

Since inflation is today regarded as a major investment risk, and since utility stocks now seem to provide a better hedge against unanticipated inflation than do

[9]Because the standard deviations in Exhibit 10 are based on the last five years of data, even if bond returns stabilize, as they did beginning in 1982, their reported volatility will remain high for several more years. Thus, Exhibit 10 gives a rough indication of the current relative riskiness of stocks versus bonds, but the measure is by no means precise or necessarily indicative of future expectations.

bonds, the interest-rate risk inherent in bonds offsets, to a greater extent than was true earlier, the higher operating risk that is inherent in equities. Therefore, when inflationary fears rise, the perceived riskiness of bonds rises, helping to push up interest rates. However, since investors are today less concerned about inflation's impact on utility stocks than on bonds, the utilities' cost of equity does not rise as much as that of debt, so the observed risk premium tends to fall.

For the 1980–1984 period, we found the following relationship (see Exhibit 6):

$$RP = 12.53\% - \underset{(0.05)}{0.63}\, R_F; \qquad r^2 = 0.73.$$

Thus, a one percentage point increase in the T-bond rate, on average, caused the risk premium to fall by 0.63%, and hence it led to a 1.00 − 0.63 = 0.37 percentage point increase in the cost of equity to an average utility. This contrasts sharply with the pre-1980 period, when a one percentage point increase in interest rates led, on average, to a 1.73 percentage point increase in the cost of equity.

Summary and Implications

We began by reviewing a number of earlier studies. From them, we concluded that, for cost of capital estimation purposes, risk premiums must be based on expectations, not on past realized holding period returns. Next, we noted that expectational risk premiums may be estimated either from surveys, such as the ones Charles Benore has conducted, or by use of DCF techniques. Further, we found that, although growth rates for use in the DCF model can be either developed from time-series data or obtained from security analysts, analysts' growth forecasts are more reflective of investors' views, and, hence, in our opinion are preferable for use in risk-premium studies.

Using analysts' growth rates and the DCF model, we estimated risk premiums over several different periods. From 1966 to 1984, risk premiums for both electric utilities and industrial stocks varied widely from year to year. Also, during the first half of the period, the utilities had smaller risk premiums than the industrials, but after the mid-1970s, the risk premiums for the two groups were, on average, about equal.

The effects of changing interest rates on risk premiums shifted dramatically in 1980, at least for the utilities. From 1965 through 1979, inflation generally had a more severe adverse effect on utility stocks than on bonds, and, as a result, an increase in inflationary expectations, as reflected in interest rates, caused an increase in equity risk premiums. However, in 1980 and thereafter, rising inflation and interest rates increased the perceived riskiness of bonds more than that of utility equities, so the relationship between interest rates and utility risk premiums shifted from positive to negative. Earlier, a 1.00 percentage point increase in interest rates had led, on average, to a 1.73% increase in the utilities' cost of equity, but after 1980 a 1.00 percentage point increase in the cost of debt was associated with an increase of only 0.37% in the cost of equity.

Our study also has implications for the use of the CAPM to estimate the cost of equity for utilities. The CAPM studies that we have seen typically use either Ibbotson-Sinquefield or similar historic holding period returns as the basis for estimating the market risk premium. Such usage implicitly assumes (i) that *ex post* returns data can be used to proxy *ex ante* expectations and (ii) that the market risk premium is relatively stable over time. Our analysis suggests that neither of these assumptions is correct; at least for utility stocks, *ex post* returns data do not appear to be reflective of *ex ante* expectations, and risk premiums are volatile, not stable.

Unstable risk premiums also make us question the FERC and FCC proposals to estimate a risk premium for the utilities every two years and then to add this premium to a current Treasury bond rate to determine a utility's cost of equity. Administratively, this proposal would be easy to handle, but risk premiums are simply too volatile to be left in place for two years.

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