Public Utilities Commission

State of Minnesota

Utility Rates Study

June 2010

REPORT TO THE LEGISLATURE:
UTILITY RATES STUDY
AS REQUIRED BY LAWS OF MINNESOTA, 2009, CHAPTER 110

Submitted by the
Minnesota Public Utilities Commission

June 2010

INTRODUCTION

Laws of Minnesota 2009, Chapter 110 (S.F. No. 550) require the Minnesota Public Utilities Commission (MPUC) to prepare a Utility Rates Study. Specifically, the MPUC is to assess special mechanisms that allow cost recovery outside a general rate-case proceeding for specific kinds of expenditures. The specific issues the MPUC must address are as follows:

- an assessment of the impact of automatic cost-recovery mechanisms on prices charged to utility consumers compared to traditional cost-recovery mechanisms
- an assessment of the impact of automatic recovery mechanisms on the level of customer understanding of utility rates compared to traditional cost-recovery mechanisms
- an assessment of alternative forms of utility rate regulation that may be used in place of automatic cost-recovery mechanisms
- methods to improve administration and customer understanding of automatic cost-recovery mechanisms [1]

In an effort to develop resources for the report, the Commission sought the assistance of the National Regulatory Research Institute (NRRI). Besides providing topical materials, the NRRI published a report in September of 2009 entitled "How Should Regulators View Cost Trackers?" A copy of that report is incorporated as part of this report as Attachment A. The Commission also participated in an NRRI national webinar entitled "The Two Sides of Cost Trackers: Why Regulators Must Consider Both," which occurred on October 27, 2009. In addition, the NRRI created a "Knowledge Community" on cost trackers on its web page. Knowledge Communities are blogs open to regulatory commission personnel for purposes of sharing information and discussing topics of mutual interest.

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[1] The language from the Law is as follows:

> Sec. 33. **UTILITY RATES STUDY.** The Public Utilities Commission, in consultation with the Office of Energy Security, shall conduct a study of automatic cost-recovery mechanisms and alternative forms of utility rate regulation. This study shall include an assessment of the impact of automatic cost-recovery mechanisms on prices charged to utility consumers compared to traditional cost-recovery mechanisms, an assessment of the impact of automatic recovery mechanisms on the level of customer understanding of utility rates compared to traditional cost-recovery mechanisms, and an assessment of alternative forms of utility rate regulation that may be used in place of automatic cost-recovery mechanisms. The study shall also address methods to improve administration and customer understanding of automatic cost-recovery mechanisms. The commission shall submit this report to the legislature on or before June 30, 2010. The commission may assess public utilities for the cost of the study. The assessment is not subject to a cap on assessments provided by section 216B.62 or any other law.
> **EFFECTIVE DATE.** This section is effective the day following final enactment.

The Commission also convened a stakeholder open forum on January 29, 2010. Participants included: Xcel Energy, Minnesota Power, Otter Tail Power, Alliant Energy, Great River Energy, Dakota Electric Cooperative Association, CenterPoint Energy, the Minnesota Chamber of Commerce, the Izaak Walton League, the Office of the Attorney General, the Office of Energy Security (OES), Senate staff members, and representatives of large industrial customers. In addition, written comments were received from several parties on February 19, 2010 (under docket number E,G-999/CI-09-1338).

Background – Cost Recovery in Rate Cases

Setting rates for utilities is based on the principle of providing a reasonable opportunity[2] to earn a rate of return that recovers costs that were prudently incurred and necessary for the provision of safe and reliable utility services, including financing costs and a reasonable rate of return to investors. This opportunity is a condition of economic regulation as it has evolved in the United States over more than 100 years whereby entities deemed to be "affected with a public interest"[3] have been granted exclusive franchises (i.e., monopolies) for specific service areas and, in return, are subject to rate regulation by a public body, e.g., a state utility commission. The exclusive franchise obviously affords considerable financial security; the public rate regulation ensures that franchise authority is not abused.

State utility commissions traditionally make the determination of whether costs were prudently incurred, were necessary for the provision of reliable utility service, and were assigned a reasonable return as part a general rate case proceeding. A formal rate case includes a detailed review of all financial factors affecting utility operations. All revenue and cost categories are reviewed: those that increase as well as those that decrease. The goal is to establish rates that are reasonable (i.e., adequate to provide safe and reliable service) and also provide sufficient return to allow utilities to attract capital on reasonable terms to finance capital investments. So the process of setting rates that are in the public interest requires a balancing of utility financial viability with a sense of what is reasonable for ratepayers.

The rate level is established in a rate case using a "test year," which is a representative 12 month period of normal utility operations. In Minnesota, utilities may use a historical test year adjusted for known and measurable changes, or a forecasted test year. Under either type of test year, the objective is to reflect normal utility operations for the time period the new rates are likely to be in effect. For example, normal weather is assumed when estimating expected revenues and expenses for the test year.

Under traditional ratemaking principles, utilities may not change rates charged to customers outside of a rate case. Costs related to new plant investments, for example, are not reflected in

[2] "Opportunity" refers to a prudently-managed utility having a good chance of earning its authorized rate of return; it is not a guarantee or an entitlement that the authorized return will be earned each year.

[3] *Munn v. Illinois*, 94 U.S. 113 (1877)

rates until the plant is completed and providing service to customers, and related investments and expenses have been determined by the Commission to be prudent and reasonable through review in a rate case.

Rate cases involve many complex issues and take time to complete. As a result, the traditional rate-making process involves a delay between the incurrence of costs and the implementation of rates that recover these costs. In regulatory parlance, this is called "regulatory lag."[4] During the period between rate cases, rates remain at the level established in the last rate case decision; i.e., they "lag" the changing conditions since the rate case.

If a utility's costs are generally increasing during the period between rate cases, unchanging rates will make it more difficult for the utility to have a reasonable opportunity to earn its authorized return. Under these conditions, the opportunity to recover costs and to earn the authorized return will depend on the utility's ability to achieve greater efficiencies in operations; i.e., the unchanging rates create efficiency incentives. As that potential is exhausted, a new rate case filing becomes more likely. On the other hand, if costs generally decline and/or revenues increase after a rate case process, the established rates virtually assure recovery, and will enhance the utility's ability to earn its authorized return; it may result in over-recovery in some situations. So lag between rate cases can have varying effects on the opportunity the utility has to recover costs and earn its allowed return, and has an effect on incentives for efficiency.

Minnesota law provides for substantial mitigation of regulatory lag for rate increases compared with many other states. Utilities in Minnesota control the timing and frequency of their rate case filings. Utilities may use forecasted test years, allowing projected cost increases to be reflected in rates. The utility is entitled to implement interim rates within 60 days of filing a rate case, and those rates are in effect until new final rates are implemented as a result of the rate case. Interim rates are essentially a "make-whole" concept, allowing utilities to reflect cost increases for costs of the same nature and kind and the same rate of return allowed in the most recent rate case, with some exceptions for "exigent circumstance". Also, the Commission must issue a final order within a statutorily defined period.[5]

The extent of lag between changes in cost conditions and a correspondingly adjustment in rates is affected by whether costs are increasing or decreasing. There is likely to be more regulatory lag when a utility is over-earning. Utilities in Minnesota are under no obligation to file, and have not filed, rate cases asking for *decreases* in rates. The Commission can require a utility to

[4] Part of this time is occupied by management's decision-making process about when to file a rate request. The rest is due to the time required for administrative proceedings before the regulatory body. These will vary by state.

[5] Minn. Stat. §216B.16, subd. 2(a) sets a 10 month due date for Commission action. Minnesota Laws, 2009, Chapter 110 amended Minn. Stat. §216B.16, subd. 2(f) to allow the Commission to extend the period for a total of 90 additional calendar days.

file a rate case if the Commission believes the utility's rates may be unreasonable,[6] but it is a lengthy process. First, the Commission needs to have information about the utility's earnings on a Minnesota jurisdictional basis; the most accessible sources of such information are the annual reports utilities file on May 1 of each year for the previous calendar year, already a lag in information. Then the Commission must (on its own motion or at the request of the OES or others) conduct an earnings investigation, including a hearing process. After the investigation and hearing process, if the Commission finds it warranted, it can require the utility to initiate a rate proceeding; but under statute, the Commission must allow the utility at least 120 days to make the rate filing. It is unlikely that the utility would request a decrease in rates in its mandated rate filing, and if any decrease is warranted, it would only happen after the full 10-13 month rate case process.

Background – Alternative Cost Recovery Mechanisms

The principle of "reasonable opportunity to recover costs and earn the authorized return" may be eroded if cost factors between rate cases change *dramatically* and *unpredictably,* are *substantial in magnitude,* and are due to factors that are *beyond the control* of the utility. For such situations, it may be appropriate to allow outside-of-rate-case mechanisms under which costs can be tracked, and potentially recovered, without requiring a rate case to be filed.

Special cost recovery mechanisms allow a utility to recover its actual costs for a specified function on a periodic basis *outside* the context of a formal rate case. They generally involve a method for tracking specific cost categories, coupled with some form of flexible rate adjustment mechanism (e.g., a rate rider) to generate the required revenues. These special mechanisms are variously referred to as automatic adjustments, cost trackers, and rate riders; while there are technical distinctions that can be made between these terms, this report will use them more-or-less interchangeably.

Special cost recovery mechanisms have been used for purchased gas and electric fuel costs for many years in most states. In Minnesota, these are the Purchase Gas Adjustment (PGA) for the commodity cost of natural gas, and the Fuel Clause Adjustment (FCA) for the commodity cost of fuels used to generate electricity; e.g., coal, natural gas, uranium (Minn. Stat. §216B.16, subd. 7). Use of fuel cost recovery mechanisms helps assure reasonable rates by providing an efficient means of adjusting required revenues to sustained and dramatic changes in fuel costs. Without a special recovery mechanism, frequent rate filings might be needed to ensure that rates cover the reasonable cost of providing reliable service.[7] In addition, financial market ratings could be adversely affected in the case of sustained and dramatic fuel cost increases,

[6] Minn. Stat. §216B.17, subd. 1 and 8.

[7] As CenterPoint Energy pointed out in its comments for this inquiry: "absent a PGA [Purchase Gas Adjustment], even a 10 percent over recovery of gas costs could potentially double an LDC's [Local Distribution Company] net income, while a 10 percent under recovery of gas costs could potentially eliminate an LDC's entire net income." Comments of CenterPoint Energy, Docket No. E,G-999/CI-09-1338, page 2.

thereby increasing financing costs.[8] The PGA and FCA also require that *decreases* in costs be passed along to consumers in a timely manner.

When the PGA and FCA were established in Minnesota in the mid-1970s, both wholesale natural gas commodity and transportation rates were federally regulated; therefore the rates paid by local distribution utilities were largely outside their control. Natural gas commodity rates have since been deregulated, and may be subject to greater fluctuation. The electric market has changed significantly since FCAs were first established, especially with the advent of the wholesale energy market established by the Midwest Independent System Operator. The Commission and other stakeholders are continuing to evaluate whether changes are needed to current FCA mechanisms to reflect these market changes.

In recent years, utilities have increasingly sought special cost recovery mechanisms for various types of expenditures beyond just fuel costs. These were prompted by the imposition of policy mandates, as well as the desire to recover very large capital expenditures for single projects (or a group of related projects)[9] or to simply encourage certain types of expenditures. Since the establishment of the PGA and FCA in 1974 in Minnesota, the following cost recovery mechanisms have been established in statute:

- Conservation improvement/incentives (Minn. Stat. §216B.16, subd. 6b)
- Performance-based gas purchasing adjustment (§216B.16, subd. 7a)
- Transmission cost adjustment (§216B.16, subd. 7b)
- Transmission asset transfer (§216B.16, subd. 7c)
- Low-income electric discount (§216B.16, subd. 14)
- Demand Side Management financial incentives (§216B.16, subd. 6c)
- Natural gas utility infrastructure (§216B.1635)
- Renewable energy power purchase agreements/investment/Renewable Development Fund (§216B.1645, subd. 2)
- Utility owned renewable facilities (§216B.1645, subd. 2a)
- Settlement – Mdewakanton Prairie Island (§216B.1645, subd. 4)
- Emissions reduction rider (§216B.1692, subd. 3)
- Mercury emission reduction (§216B.683)
- Real and personal property taxes (§216B.241, subd. 2b)
- Reliability Administrator (§216C.052)
- Gas Affordability Program costs (§216B.16, subd. 15)
- Electric infrastructure costs (§216B.1636)
- Greenhouse gas infrastructure (§216B.1637)

[8] For example, Interstate Power cites a recent report by Standard and Poor's which states: "[Standard & Poor's] views rate recovery mechanisms that allow for the timely adjustment of rates to changing commodity prices and other expenses, outside of a fully litigated rate proceeding, as beneficial to utility creditworthiness." S&P Research: "Recovery Mechanisms Help Smooth Electric Utility Cash Flow and Support Ratings," March 9, 2009.
[9] For example, Xcel's Metropolitan Emissions Reduction Program.

- Decoupling (§216B.2412)
- Central Corridor utility zone cost adjustment (§216B.16, subd. 7d)

The costs covered by many of these recovery mechanisms are substantially smaller in magnitude than fuel costs and, therefore, they do not fit as neatly the theoretical rationale for special recovery mechanisms. The common denominator in the more recent additions was a perceived need to remove disincentives to investment in areas where the pure economics were asserted to be not singularly compelling, but which, nevertheless, advanced public policy goals; e.g., renewable generation, emission reduction.

Although special recovery mechanisms can help assure reasonable rates in certain circumstances and, when used properly, can provide immediate and cost-specific price signals to utility customers, which (again, in theory) should lead to better consumption decisions, there are concerns with their use. For example, their use can have an adverse affect on incentives. By eliminating regulatory lag and allowing immediate pass-through of certain types of cost increases, meaningful and binding incentives to control costs could be substantially eroded. Contrast this with business entities that are not protected from competition by regulation but are subject to robust competitive pressures. These entities have little or no ability to pass through cost increases, but must constantly find ways to cut costs to stay competitive. In addition, the greater the number of cost categories subject to automatic recovery, the greater the effect on cost containment incentives. The OES noted in its comments that Minnesota utilities have, in fact, pushed for expedited review of special recovery mechanisms, and have opposed measures that would help ensure that costs are reasonable, like competitive bidding or holding utilities to their own cost projections.[10]

In addition, allowing automatic cost recovery in some functional areas but not others could also create contrary incentives for cost-minimizing activities. For example, allowing automatic recovery for fuel might also create an incentive to postpone maintenance of plant, for which there is no automatic recovery. In other words, it may be more profitable to simply burn more fuel than to make plants operate more efficiently. Moreover, selective allowances like this one for fuel could create an incentive to characterize as many costs as possible as "fuel" in order to obtain automatic recovery.

Special cost recovery mechanisms can be very effective for incentivizing investment in certain technologies. That phenomenon is well understood and, in fact, has been employed strategically in recent years to accomplish public policy goals. However, as a practical matter, the need for special recovery seems to have been asserted only for cost categories that were expected to *increase*, with little or no provision for any savings or sharing of benefits that might also result from such investments and without consideration of the utility's actual earnings level. In fact, these mechanisms have been sought with no demonstration offered of the financial implications to be expected in the absence of the special mechanisms, or how the

[10] Comments of the Minnesota Office of Energy Security, Docket No. E,G-999/CI-09-1338, page 5.

mechanisms serve the public interest and not just the financial goals of the company. Finally, given the proliferation of trackers now available and in use, the amount of time required to track and manage each special recovery mechanism has become considerable; certainly for regulators, and presumably for utilities.

Automatic cost recovery mechanisms are increasingly popular, but there are other options for encouraging investments that support public policy or state energy goals. Those alternatives will be discussed in more detail below.

IMPACT ON RATES:

As noted, under certain cost conditions, use of special recovery mechanisms can eliminate the adverse effects of regulatory lag and help assure reasonable rates. If costs are largely outside the control of the utility, are unpredictable and volatile, and are substantial and recurring, it is less likely the utility will have a reasonable opportunity to recover prudent costs and will, therefore, incur added financial risk. The use of special recovery mechanisms under these conditions will help to avoid the cost of the frequent rate proceedings needed to adjust rates to changing conditions and, possibly, help to limit financing costs by dampening the financial risk to the company. In other words, use of special recovery, in certain circumstances, should help to ensure that rates reflect the true cost of providing the utility service.

The probable impact of special cost recovery mechanisms in practice is less clear. As noted, they inherently create the potential for unproductive incentives. For example, even the use of automatic adjustment for fuel costs can create an incentive to include other cost factors in the definition of "fuel." In Minnesota the FCA mechanism has been expanded to include other categories of costs, including, performance-based gas purchasing programs (Minn. Stat., Chapter 216B.16, Subd. 7a), transmission costs (Minn. Stat., Chapter 216B.16, Subd. 7b); and greenhouse gas infrastructure costs (Minn. Stat., Chapter 216B.1637), to name a few.

The risk to incentives is especially significant when special recovery is allowed for cost categories that do not inherently pose a danger of severe financial risk; i.e., costs that are *not* always outside the control of the utility, unpredictable or substantial. In those instances, allowing automatic recovery would also be expected to erode incentives for cost control.

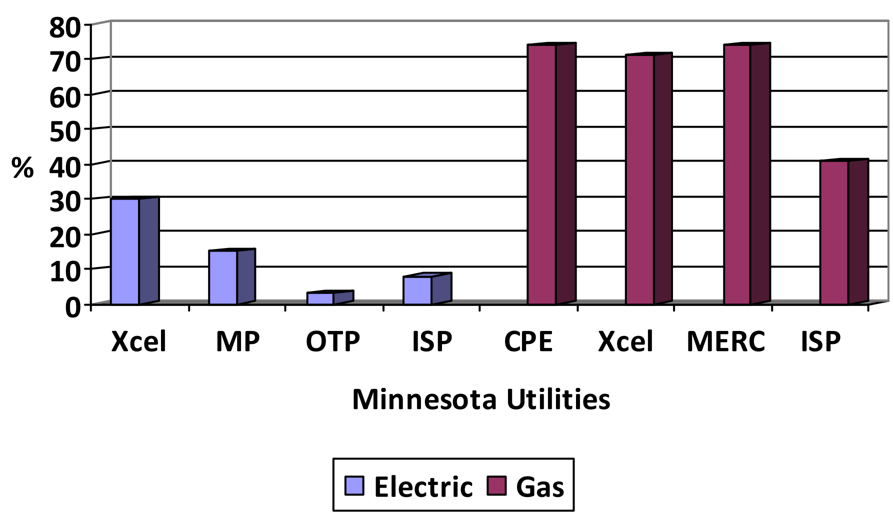
Moreover, making certain cost categories subject to automatic recovery removes them from inclusion in the overall review of costs (those that decrease as well as those that increase) when a general rate case is ultimately filed. It effectively takes them "off the table" in a rate case review and thereby constricts the Commission's rate-making authority. And while special recovery will have the effect of dampening the magnitude of rate requests that utilities make when they do ultimately file a rate case petition, the reality is this effect merely masks the full rate implications for ratepayers.

Attempting to quantify the impact of special cost recovery mechanisms on rates compared to traditional cost recovery mechanisms is not a simple, straight-forward process. The primary method used here is to determine the jurisdictional operating revenues produced by the automatic cost recovery mechanisms utilized by Minnesota's utilities and evaluate their general impact on utility financial conditions.

Appendix A shows, for each cost tracker currently allowed in Minnesota, the amount of revenue each utility collected in 2009, which is the most recent year for which full company information is available.. Appendix A shows that revenues collected under the fuel-related recovery mechanisms far surpass all other automatic recovery mechanisms combined, representing 90% of all revenues collected by automatic recovery mechanisms in 2009. The next largest tracker mechanism is the long-standing mechanisms for Conservation Improvement Program (CIP) costs, which collected 4.8% of total tracker account revenues in 2009. The trackers for emissions reductions and renewable energy power purchase agreements (PPAs) were a distant third (with 1.6%) and fourth (with 1.1%). In other words, the revenues generated by Minnesota's more recent special recovery mechanisms (i.e., other than for fuel and CIP) accounted for less than 3% of the total revenue collected in 2009.

Because the commodity cost of gas is significantly larger than the cost of distributing it to customers, gas utilities inherently recover a larger percentage of revenues through the fuel recovery mechanism. For example, approximately 74% of the 2009 Minnesota jurisdictional revenue for CenterPoint Energy (CPE) was collected via fuel recovery mechanisms compared to 3% for Otter Tail Power (OTP). Figure 1 provides a comparison of fuel recovery revenues as a percent of 2009 annual Minnesota jurisdictional revenues for electric and gas utilities.

Figure 1 Fuel Recovery Revenues as % of Total Company Revenues - 2009



Although both electric and gas utilities use the special recovery mechanisms for fuel and CIP, most of the more recent mechanisms are geared for electric utilities and, therefore, electric utilities use more special recovery mechanisms compared to gas utilities. Among electric utilities, Xcel utilizes the most special mechanisms. In 2009, Xcel's Minnesota electric utility collected approximately $74 million through the automatic adjustment mechanisms.[11] This $74 million represented less than 1% of the utility's total jurisdictional revenues. Minnesota Power collected approximately $29 million in 2009 through the mechanisms for transmission costs and emissions reduction; i.e., 4% of its jurisdictional revenues. Otter Tail Power collected approximately $6 million through the mechanisms for renewable energy PPAs; i.e., also about 4% of its revenues. By contrast, the revenues collected in 2009 through these non-fuel and non-CIP recovery mechanisms by Minnesota *gas* utilities averaged 0.3% of their total revenues. So even though electric utilities utilize more of these more recent mechanisms and collect a larger amount of revenues than gas utilities through their use, the financial impact of these more recent recovery mechanisms is still small for both electric and gas utilities.

Another dimension to the effect of automatic recovery mechanisms on rates is the amount of time spent by utilities and regulators to manage the various cost tracker mechanisms. Time spent to manage these projects translates to regulatory costs which are recoverable in rates.

The Commission has had 679 filings involving one or more of the various automatic cost recovery mechanisms since 2005; beginning with 51 in 2005 and including 147 in 2009.[12]

Figure 2 Number of automatic recovery filings since 2005

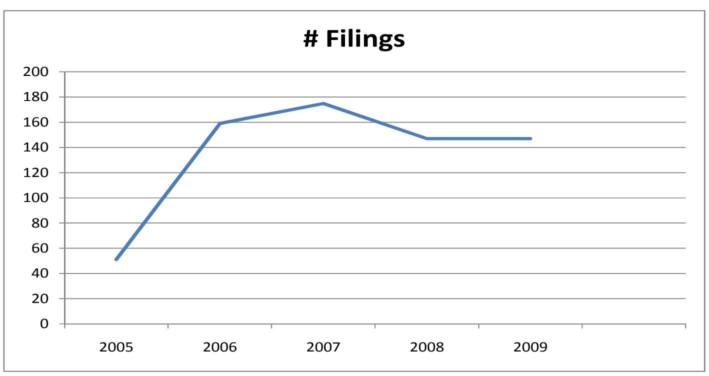


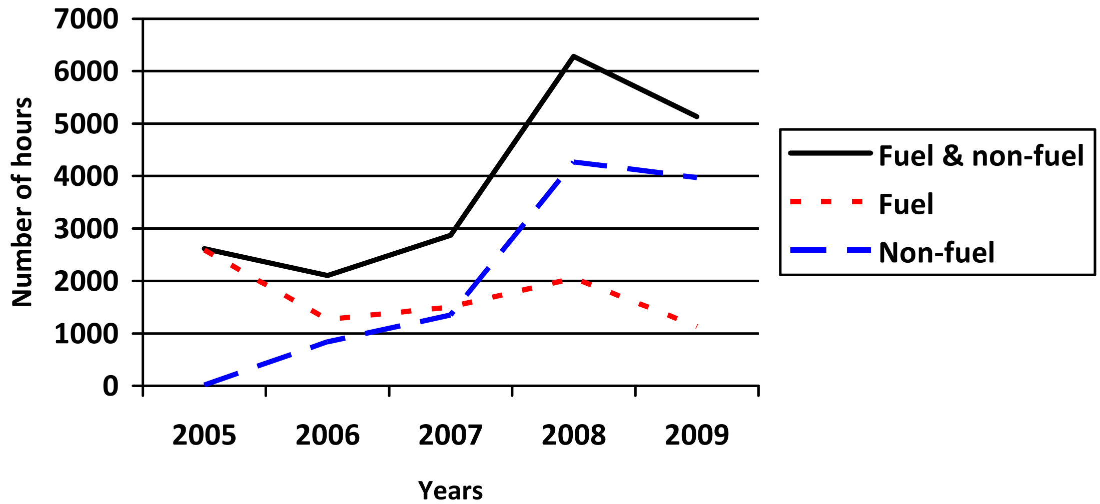
Figure 3 shows that this sustained increase in filings was driven by non-fuel recovery mechanisms. Figure 3 also slows that the amount of time spent by PUC and OES staff and

[11] For transmission costs, greenhouse gas infrastructure, renewable energy PPAs/investment/Renewable Development Fund, emissions reduction, and reliability administrator support

[12] 2007 had the largest number of such filings during this period with 175.

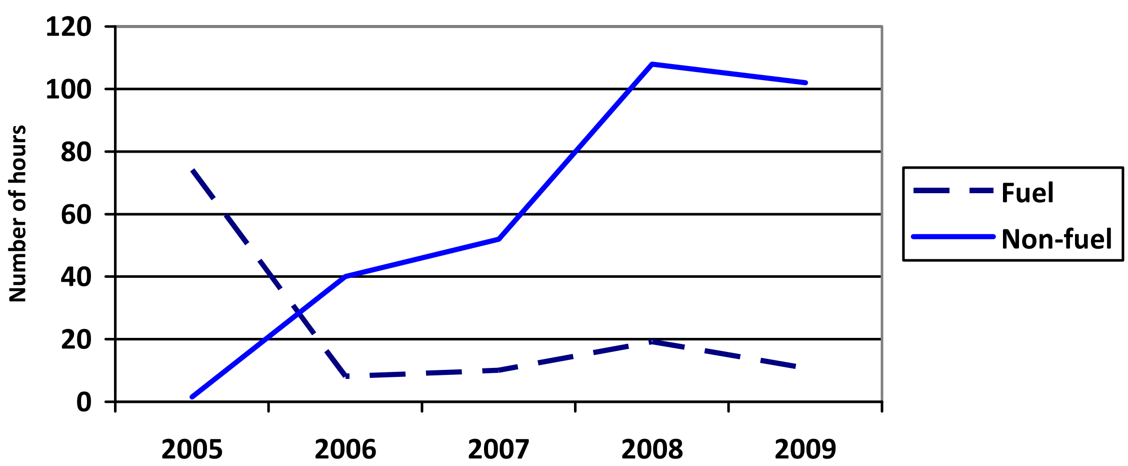
commissioners on fuel-related mechanisms remained relatively flat over this period, while the time spent on non-fuel mechanisms has increased significantly.

Figure 3 Hours Spent by PUC & OES staff on Automatic Recovery Filings



Not only are there more non-fuel-related filings, but these filings are also taking more time to complete. Figure 4 shows that the average number of hours spent by PUC and OES on non-fuel-related filings has greatly exceeded the average time spent on fuel related filings.

Figure 4 Average Hours on Fuel-related vs. Non-fuel-related



However, the prevalence of numerous special recovery mechanisms has not markedly reduced the number of rate case filings. Since January 1, 2005, the Commission has had 18 new rate case filings; i.e., an average of 3 new rate case filings per year. This contrasts markedly with rate case activity in the 1990s and early 2000s, when one filing per year (or less) was the norm.[13] It is noteworthy that most of the non-fuel-related recovery mechanisms have been adopted since that "quieter" time. And although rate cases require a large commitment of resources for both regulator and regulated, the cumulative requirements of those more recent special recovery mechanisms have grown in magnitude and now constitute a major source of activity for the PUC and OES.[14]

These trends confirm that utilities have become much more active in recent years in seeking general rate increases as well as recovering more revenues automatically through automatic recovery mechanisms. However, whether rates are higher or lower because of the existence of special recovery mechanisms remains a difficult question to answer precisely.

It seems very likely that the number of rate case filings as well as the dollar amount of individual rate case requests since 2005 would have been even greater in the absence of *any* automatic recovery mechanism. Certainly special recovery for fuel costs has mitigated the number of rate case filings. And because the fuel cost recovery process adjusts for *decreases* as well as *increases*, unlike the other mechanisms, its use provides a more accurate tracking of fuel costs over time and, therefore, a better price signal to end-users. On the other hand, as noted earlier, use of special recovery mechanisms can also divert certain costs from the rate case process and therefore can mask the true impact on ratepayers. There are other concerns as well.

The availability and use of a special recovery mechanism lightens utilities' responsibility to manage the risk associated with the specific cost category and shifts some of that burden to ratepayers. In theory, this would be expected to erode incentives for efficiency and cost control, creating upward pressure on rates. Whether that is true and the extent of the impact on rates remains unmeasured under the current array of mechanisms. Adding specific performance requirements and providing an enforcement mechanism would be a means to limit such adverse effects on incentives.

Because special recovery mechanisms have the effect of transferring risk away from utility shareholders, their use is viewed favorably by the financial markets and, theoretically, should result in a lower cost of capital for the utility and, thus, help relieve pressure on rates. However, Minnesota utilities are not required to demonstrate any such effects and it is not clear the extent to which any savings are, in fact, shared with ratepayers.

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[13] Factors contributing to the increase in rate case activity include increasing state public policy requirements (e.g., renewable energy, emission reduction, energy efficiency), a federal policy shift to greater integration of transmission services at the regional level along with critical transmission infrastructure upgrade demands, and the downturn in the economy in general.

[14] As of 2009, special cost recovery filings required approximately 5,000 hours of PUC and OES time, compared to approximately 11,000 hours for rate cases during the same period.

CUSTOMER UNDERSTANDING:

The issue cited by most ratepayers who express concern about their utility bills is the *total* amount of the bill and how that obligation fits within their budget. In addition, customers occasionally question whether the amount they must pay represents fair value for the service they receive. Ratepayers clearly regard utility expenditures as an important outlay, but one of several necessary outlays. For most, their awareness of the differences between utility prices versus other goods or services focuses on why utilities are allowed to operate in a monopoly setting when other businesses are not; and why the utility does not manage its charges for services within the set rates they are granted, rather than those base amounts plus cost recovery charges.

Although ratepayers' specific awareness of the use of special recovery mechanisms is relatively low, the Commission has, in recent years, received questions and comments from a small but growing number of ratepayers about the additional charge types that have appeared on their bills, many of which are due to special recovery mechanisms. These concerns focus on complexity of the bill, as well as opinions (pro and con) on the merits of the underlying public policy prompting the charge. The occurrence of these ratepayer contacts seem to have been contemporaneous with the implementation of special recovery mechanisms. Ratepayer reaction would be expected to be related to the number of special mechanisms employed and the amount of revenue collected through their use; i.e., were the number of mechanisms and/or the amount of revenue thus collected to increase, we would expect to see a corresponding increase in ratepayer contacts.

Since customers generally are not engaged on these more nuanced issues of special cost recovery, greater public attention to the implications of their use alone may not ensure the protection of ratepayer interest. Consequently, sharing with ratepayers the efficiency gains resulting from special recovery measures should be an element of special recovery mechanisms.

ALTERNATIVES:

The use of automatic cost recovery mechanisms has been expanded in recent years in response to utility claims about the effects of increased uncertainty and heightened concerns that regulatory lag leads to financial effects for utilities that are more adverse than favorable. Authorizing the use of mechanisms that help reduce risk for utilities and make it more likely they will have a reasonable opportunity to recover costs and earn their authorized return may not be unreasonable for entities that are called upon to not only provide essential services, but to do so in a manner that addresses pressing policy needs. On the other hand, the expanded use of these mechanisms can lead to reduced efficiency and increased administrative costs, both of which will put upward pressure on rates, as well as contribute to customer confusion.

Therefore, if it is agreed that traditional regulation requires some degree of modification to address more dynamic industry conditions, the question is: Are there viable alternatives?

Special cost-specific recovery mechanisms of the type discussed above are just one type of alternative options for reducing recovery uncertainty for utilities. Other examples include the following:

1. Recovery of construction costs during construction, rather than only after construction;
2. Approval of specific projects in advance of completion (i.e., "pre-approval");
3. "Securitization," which is a government guarantee of cost recovery, intended to reduce financing costs; [15]
4. Some form of Earnings Sharing Mechanism (ESM), which essentially creates one rate-of-return tracker designed to allow adjustments that enable the utility to earn its authorized return all the time.

Construction Work in Progress

Construction Work In Progress (CWIP) is an accounting method for accumulating expenditures related to the design and construction of major facilities before they are completed and put into service. In traditional utility ratemaking, the utility is not allowed to earn a rate of return on these investments until the plant is used and useful in providing utility service. Instead, the financing costs are "capitalized" and become part of the total plant cost included in the rate base on which the utility may earn a return, after the plant is completed and the associated investment and costs are found to be prudent and reasonable in a rate case.

An alternative approach to CWIP is to allow the utility a current return on its investments in major facilities while they are still under construction, either through inclusion in rate base in a rate case, or through a rider mechanism. This technique reduces the risk of non-recovery and aids in cash flow during construction, which may help keep financing costs lower. However, allowing recovery in rates before a plant is completed may not allow for meaningful review of the reasonableness of the total costs of the project and may result in ratepayers paying for facilities that are never completed or that have significant cost overruns.

Current Minnesota law allows the Commission to include CWIP in the rate base upon which the utility earns a return in a rate case under certain circumstances, but the Commission rarely has done so.[16] Certain rate rider statutes, including those related to utility-owned renewable

[15] For more details, see *Pre-Approval Commitments: When And Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?* The National Regulatory Research Institute, November 2008,

[16] Minnesota Statute, §216B.16, Subdivision 6a, allows the Commission discretion in determining the extent to which income used in determining the actual return for the utility shall include an allowance for funds used during construction.

facilities and transmission, explicitly allow the Commission to permit recovery of CWIP through the rider, and the Commission has generally allowed such recovery. Allowing a current return on CWIP for these types of facilities, and for other major facilities, could instead be done routinely in general rate cases.

Pre-approval

Pre-approval of major projects by regulatory commissions is another method to reduce the risk to utilities, and may be used alone or in combination with allowance of CWIP in rates and/or rate riders. Pre-approval review processes generally involve a determination by the regulatory commission that a project proposed by the utility is reasonable *prior* to starting construction. This gives the utility a reasonable assurance that the costs related to the project, as long as it is prudently managed, will be allowed future recovery in rates. This lowers risk to the utility and may result in an enhanced ability to raise capital at reasonable cost.

A specific pre-approval process for certain environmental improvements became part of Minnesota Law during the 2010 Session. Laws of Minnesota, 2010, Chapter 373 allows a utility to petition the Commission for an advance determination of prudence for a project expected to cost Minnesota ratepayers $10 million or more and which is needed to comply with federal or state air quality standards. The utility may begin recovery of costs that have been incurred for the project, and which are shown to be reasonable and necessary, in the next rate case following the advance determination of prudence. However, the Commission has some discretion on the specific costs to allow, including whether to allow a current return on CWIP during construction.

Securitization

Securitization, as the term is used here, does not refer to the conversion of financial assets into other marketable securities (which has been much in the news of late), but to the granting of a statutory right to cost recovery for utilities in order to avoid “stranded investment” in transition to deregulated energy markets. Securitization, in this sense, was adopted in California and some other states which opted for deregulation of the electric industry in the 1990s. The granting of a statutory right to cost recover eliminated substantial risk for utilities operating in these conditions and did so by shifting that risk to all state *taxpayers* instead of just the company’s ratepayers. More recently, some states have allowed securitization to be used to finance major storm recovery efforts, environmental improvements, and discussion is taking place about the possibility of using securitization for Greenhouse Gas (GHG) reduction measures. Such measures have not been enacted, or seriously considered to date, in Minnesota.

An *Earnings Sharing Mechanism*

An Earnings Sharing Mechanism (ESM) would replace the array of special recovery mechanisms with one mechanism based on rate-of-return. [17] Generally, an ESM allows adjustments outside of rate case proceedings for both: (1) actual costs deviating from the level of costs identified in the test year used in the most recent rate case, and (2) actual revenues deviating from test year revenues. [18] However, an ESM would constitute a *major change* from traditional rate-making, and were a version of an ESM to be pursued in Minnesota, considerable attention would need to be devoted to preserving equity and avoiding unnecessary additional pressure on rates.

An ESM can take different forms. In general, rates are initially set in a rate proceeding and then, pursuant to some sort of review of costs, revenues, and earnings, adjustments would be allowed periodically to achieve certain targets. Typically, an ESM would target a certain rate of earnings, i.e., an authorized rate of return as established in a full rate case. Ideally, an ESM would also involve a return on equity band (ROE band), which is a range around the authorized rate of return. With an ROE band, no automatic rate adjustments are allowed as long as the overall earnings are within the band, but would be permitted if earnings are outside the band. For example, if 10-14% is set as the ROE band around the authorized rate of return of 12%, then rates could be adjusted upward if the actual return falls below 10%. The adjustment could be geared to increase the return closer to the minimum level specified in the ROE band, i.e., 10%. Conversely, rates could be adjusted downward to address actual earnings above the band. [19] As noted, these adjustments would occur through some form of regulatory review, but without full rate case review.

An ESM has advantages and disadvantages. As noted, its use can substantially reduce the need to administer numerous separate recovery mechanisms. Also, use of an ESM should reduce the frequency of rate cases and could result in rates that more closely coincide with changing market developments. In addition, unlike the special recovery mechanisms which track only single cost categories to the exclusion of everything else, an ESM would take into account the utility's overall profitability in adjusting rates.

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[17] *How Should Regulators View Cost Trackers?* National Regulatory Research Institute, September, 2009. Page 11. Some specific examples include: Oklahoma Performance Based Rate Change Tariff; North and South Louisiana Rate Stabilization Plan; Texas Cost of Service Adjustment. In addition, the Federal Energy Regulatory Commission employs formula rate plans for transmission ratemaking.

[18] An ESM should not be confused with decoupling. Decoupling, as it is defined in Minnesota statute, is "a regulatory tool designed to separate a utility's revenue from changes in energy sales. The purpose of decoupling is to reduce a utility's disincentive to promote energy efficiency." Minnesota Statutes, § 216B.2412. Decoupling is focused on changes in sales and is a form of a cost tracker. An ESM is typically focused on *overall earnings*; i.e., accounting for changes in all costs and all revenues.

[19] How the rate adjustments would occur and their specific magnitude would be factors in the design of the specific plan. For example, should the target of an upward adjustment be the authorized return or the minimum of the ROE? Likewise, should downward adjustments be set as "dollar-for-dollar" reductions for ratepayers or should some of the extra gain be provided the utility as a reward for good performance? Also, how often should adjustments be allowed? Should they affect all rates?

However, compared to traditional ratemaking, where rates remain fixed between rate cases, an ESM would diminish regulatory lag, which would be expected to *reduce* the incentive of a utility to control its costs between rates cases.[20] This potential effect is particularly acute if *all* cost categories are amalgamated into, essentially, one cost recovery mechanism under the ESM. As one authority put it, use of an ESM of this nature effectively puts the utility's future on "auto-pilot."[21] Also, as noted earlier, an ESM shifts a larger share of risk to ratepayers. Frequent rate adjustments will have an impact on customers, and that impact is more likely to be negative if the adjustments are always (or usually) increases. Customer confusion is also likely to be a factor, but may be offset somewhat by very deliberate informational campaigns.

There are methods to mitigate some of the adverse effects of an ESM. For example, limiting expedited rate adjustments to only those instances when *major* cost items (e.g., fuel and purchased gas) lead to earnings outside the authorized band is a way to curb adverse affects on incentives, rate volatility, and the degree of risk shift. Adverse effects on incentives could be further mitigated by requiring that the utility demonstrate prudence and provide reasons why specific cost items were higher than their test year levels.

ESM's can occur in various forms. In stakeholder comments received pursuant to the Commission's January 29 meeting on this topic, some examples were cited. One option was Formula Rate Plans (FRP). The main distinguishing feature of an FRP is the use of a specific formula to calculate automatic rate adjustments targeted to yield a predetermined ROE, given real-time changes in certain cost factors. The formula by which any rate adjustments are calculated is derived and approved as part of a general rate case proceeding. With an FRP, utilities are required to provide information periodically on the various cost and revenue factors accounted for in the formula.[22] Because the formula has been approved in advance, the periodic regulatory review is confined to scrutiny of the prudence of particular input items or to arguments that the utility has misapplied the formula.[23] However, any costs subject to an independent tracker or rider would not be included in the FRP process. For example, if it was determined that fuel costs should continue to handled via an independent automatic adjustment mechanism, these costs would not be included in the FRP formula. Appendix B provides detailed descriptions of various formula rate plans currently in effect in some other jurisdictions.

[20] It should be noted that as long as the utility's rate of return is within the "band" there would be some incentive for cost control. If it operates within that band, it has an incentive to control costs to maximize its actual return because its rates will not be changed. The difference with an ESM is that rates won't remain unchanged until the next rate case, but would be changed if there is a showing of some combination of change in costs and/or revenues that cause the actual return to fall outside the band. So the incentive would be similar to traditional rate-making but not as binding.

[21] Ken Costello, *The Two Sides of Cost Trackers: Why Regulators Must Consider Both*, the National Regulatory Research Institute. Statement made as part of a webinar on October 27, 2009.

[22] This could be cost data from the accounts of costs and revenues filed with the Federal Energy Regulatory Commission on the annual FERC Form 1.

[23] The National Regulatory Research Institute, November 2008, *op. cit.*, page19

Another variation is the Multi-Year Rate Plan (MYRP). As with FRPs, a MYRP is established and approved within the framework of a traditional rate proceeding. However, rather than allowing rate adjustments in response to changed conditions, the MYRP locks in specific future rate adjustments based on forecasts of future conditions made during the basic rate proceeding. A predetermined rate adjustment is established for each year of the MYRP's term (usually 3 to 5 years) based on future test-year revenue requirements or some sort of index, e.g., based on growth. Once a MYRP is established, rate case filings are prohibited during its term.

MYRPs rely extensively on accurate forecasting of critical cost and revenue factors. Once approved, parties must live within the specifications of the plan as it is defined which could be difficult in periods of dramatic, unexpected changes. However, MYRP can also employ earnings sharing provisions that require a utility to return earnings beyond an ROE threshold during the term of the plan. As with FRPs, costs tracked independently are typically not included in a MYRP. Appendix C provides the details of a MYRP for Consolidated Edison in New York.

IMPROVE ADMINISTRATION AND UNDERSTANDING

The final requirement of Minnesota Laws 2009, Chapter 110, section 33, is an evaluation of ways to better utilize automatic cost recovery mechanisms; i.e., how to make the current array of special recovery mechanisms operate more efficiently. Given the large number and diverse array of such mechanisms currently available and in use in Minnesota, greater efficiency in their use would require significant change. At a minimum, there needs to be a focus on reducing administrative costs and making greater provision for ratepayer sharing efficiency gains.

Three possible fundamental approaches set the continuum for further discussion; each approach has advantages and disadvantages. The three approaches are set forth below:

1. Eliminate all existing trackers that cannot demonstrate extreme financial consequences, and provide for a reasonable opportunity for cost recovery for everything else through rate case proceedings.
2. Consolidate all trackers (except, perhaps, fuel) into one overall tracker and develop a form of comprehensive ESM.
3. Substantially reduce the number of trackers to allow only those that are most commonly used, involve the largest financial impact, and incorporate the greatest accountability.

Allow special recovery mechanism only to avoid extreme financial conditions:

This approach would allow cost trackers in only special situations where the absence of a special recovery mechanism would cause *extreme* financial problems; i.e., conditions that would adversely affect customers in the long run. The classic example of such a factor is fuel costs. The National Regulatory Research Institute (NRRI), in its report, *How Should Regulators View Cost Trackers*[24] identifies the benefits of this approach:

a) Using the same cost recovery mechanisms for all utility operations *(i.e., a rate case instead of numerous individual trackers)* to prevent perverse incentives; perverse incentives can lead to a higher cost of service and utility rates.
b) Balancing a utility's total costs and total revenues *(again, through a rate proceeding)*; without this balancing, it is conceivable that the utility could recover one cost item through a tracker, and over recover other costs set in the last rate case to result in the utility earning above its authorized rate of return; a rate case has the attractive feature of matching revenues with costs on an aggregate basis;
c) Strengthening regulatory lag to provide the utility with more motivation to control costs; regulatory lag is an important feature of traditional ratemaking in forcing the utility to shoulder the risk of higher costs between rate cases; and
d) Scrutinizing a utility's costs and performance in different areas of operation; commissions seem to review costs recovered outside of a rate case less thoroughly, with the increased likelihood of customers recovering a utility's imprudent costs.[25]

With this approach, if a utility believes a special recovery mechanism is needed, it would have to *demonstrate* that it is essential to avert a very severe financial condition. This would require a showing of the impact of possible cost futures and an assessment of their likelihood. If the cost factor fits the classic profile (i.e., large in size, volatile, and out of company's control), then it would be a candidate for special recovery. But, as the NRRI points out, "even then, the regulator should consider the adverse incentive effects and how it can compensate for this problem."[26] This assessment could be done by monitoring performance or could include a performance-based incentive in the tracker mechanism.

However, limiting the use of special recovery to only the most severe conditions will make it much more difficult to "surgically" remove disincentives to certain expenditures, which, by themselves may not necessarily carry significant financial consequences, but which are seen as necessary to accomplish certain goals. Limiting special recovery to only circumstances demonstrating severe consequences restores and reinforces regulatory lag. For utilities who claim financial distress because of some cost condition, this approach "holds their feet to the fire" to demonstrate the exception is needed to minimize additional costs and will not harm incentives for efficiency. Although this approach would minimize administrative costs and would provide greater assurance automatic recovery is the exception rather than the rule, it may not offer the flexibility needed in the face of dynamic industry conditions and growing public policy imperatives.

[24] The National Regulatory Research Institute, September, 2009, *op. cit.*, pp. 15-17.
[25] *Ibid.*, p. 16
[26] *Ibid.* pp. 16-17.

Consolidating trackers into a single rate-of-return tracker:

As noted previously, an ESM can assume the role of a "rate-of-return tracker" that, in effect, amalgamates different special recovery mechanisms into a single mechanism. This approach has several noteworthy features. By consolidating all recovery mechanisms, this approach reduces the administrative costs of managing numerous individual recovery mechanisms. By allowing expedited recovery based on overall return, this approach can help address financial risk concerns of utilities.

In addition, basing rate adjustments on overall return instead of changes in a single cost factor, especially if combined with sharing mechanisms, can help ensure greater equity between ratepayers and shareholders.[27] In addition, some of the incentive problems of special recovery mechanisms can be diminished with an ESM that incorporates an ROE band, particularly if coupled with a required showing of prudence if costs exceed test-year levels.[28] Moreover, use of an ESM does not preclude use of special recovery for major cost items that by themselves pose a severe financial risk. In addition, as with any of these approaches, building in specific performance requirements can ensure public policy goals are being adequately addressed.

However, moving to an ESM type of structure represents a *major change* in Minnesota's approach to regulation. As with any such change, the "devil is in the details" and working out those details would be a contentious and time-consuming process. Given the degree of change this would represent, it would be best to limit its initial use to an experimental model, if such a change is deemed necessary. In addition, it may be a "hard sell" to explain to ratepayers the benefits of moving from the current system, which offers utilities an *opportunity* to earn an authorized return (leaving it to them to create the efficiencies required), to a system that would virtually *guarantee* a utility something very close to its authorized return with greatly reduced business risk. Consequently, there would have to be very obvious and ample provision for ratepayer benefits if such a plan is to be seriously entertained.

Reducing the number of special mechanisms but increasing accountability:

Generally, this option would aim to reduce the number of available special recovery mechanisms to only those most commonly used by utilities and involving significant financial impact. This option should also seek to consolidate remaining recovery mechanisms to save administrative costs, as well as incorporate specific performance metrics, authority to enforce requirements based on those metrics, and provisions for sharing savings with ratepayers.

[27] An ESM could allow recovery of increased costs but only if the utility was already earning a "low" rate of return (i.e., below the ROE band).
[28] As noted earlier, as long as the utility's rate of return is within the "band" region, it has some incentive for cost control, though arguably not as great as under traditional rate-making.

Although they were not necessarily advocating for this particular approach, the OES suggested a number of requirements to improve accountability and equity in the use of out-of-rate case recovery mechanisms. These suggestions provide excellent examples of the kind of new requirements that should be considered in any change in Minnesota's approach to special recovery mechanisms. The following is the list offered by the OES:

a) Requiring utilities to use a robust competitive bidding process to acquire new facilities;
b) Requiring a utility to justify why it would be in the public interest to recover costs of a project before the facility is used and useful;
c) Requiring utilities to share with ratepayers new sources of revenue obtained through resources paid for by ratepayers;
d) Not allowing utilities to recover costs through a rider above the amount the utility initially indicated the project would cost;
e) Not allowing deferred accounting for any cost overruns (utilities could request recovery of any such cost overruns at the time of a subsequent rate case; however, it should be clear that the burden of proof is on the utility to show how any such additional cost recovery should be reasonable to allowing rates);
f) Putting utilities on notice that the Commission may modify or cease the amounts recovered in riders if facilities do not perform as proposed or for any other reason necessary to protect the public's and ratepayer's interest, consistent with general ratemaking principles.[29]

The main advantages of this approach are the potential for lower administrative costs, greater accountability and sharing of benefits without the more dramatic changes associated with the other two options. The main problem with this hybrid approach is that it preserves the use some individual special recovery mechanisms with all the inherent risks to incentives that entails as well as administrative costs. Although administrative costs would be expected to be diminished through the reduction in the number of special mechanisms, building in performance standards and compliance, as well as provisions for sharing of benefits, would require administrative time. So the ultimate net impact on costs is difficult to gauge with a high degree of certainty. However, it seems likely that even if the overall costs were higher, the value delivered to end-users would be markedly greater by virtue of these additional measures.

CONCLUSIONS:

Minnesota Laws 2009, Chapter 110 posed four basic questions to be addressed by this report. The following is a restatement of those questions with a brief response summarizing the main finding of the report.

[29] Comments of the Minnesota Office of Energy Security, Docket No. E,G-999/CI-09-1338, page 5.

Question: Are rates higher or lower as a result of the special recovery mechanisms we have seen in Minnesota?

Answer: This cannot be precisely measured. However, it seems very clear that recovery mechanisms for fuel-related costs have helped to curb upward pressure on rates. The rate impact of recovery mechanisms for items other than fuel is far less clear, but there is concern that they may contribute to upward pressure on rates. Almost all of the mechanisms enacted since the PGA/FCA have been to allow accelerated recovery of costs that are increasing.

Question: Has customer understanding of utility rates been enhanced or diminished as a result of these special recovery mechanisms?

Answer: Generally, customers are more concerned about their total utility charges and how those fit within their income and other expenses than with what components comprise those charges. However, while the questions and comments of customers that have been raised with the Commission regarding special recovery charges have been relatively few, they have been growing over the last several years. Given this timing, there may be a correlation with the recent increase in the type and overall number of special recovery mechanisms. Since customers generally are not engaged in these issues, greater public attention alone will not ensure the protection of ratepayer interest. Consequently, sharing of efficiency gains with ratepayers should be an element of special recovery mechanisms.

Question: Are there alternatives that should be considered?

Answer: There are alternatives to the array of special recovery mechanisms currently in effect in Minnesota. There are advantages and disadvantages to each. All would afford utilities protection from risk beyond that afforded by the franchise monopoly they currently possess. All tend to shift risk from the utility to ratepayers.

Question: Are there ways to make the current system work better?

Answer: The current system of numerous special recovery mechanisms has become cumbersome, raises concerns about cost control, and has constrained the Commission's primary ratemaking instrument, the general rate case. Improving the current system will require adjustments to ensure greater accountability and a sharing of benefits with ratepayers. Fundamentally, the question is whether there are better ways to incentivize utility performance to ensure public policy goals are met. There are alternatives and they each should be evaluated through further discussion and inquiry.

The major thrust of the answers to these questions, and of this report in general, is that a fundamental reassessment of the current use of special recovery mechanisms is in order. This report is intended to provide a foundation for that reassessment and, hopefully, some structure for moving forward. The Commission believes there is need for continued dialogue among legislators, utilities and other stakeholders about the alternatives presented here and about possible future steps. We look forward to having that discussion.