LARGE FILING SEPERATOR SHEET

CASE NUMBER: 07-589-GA-AIR
07-590-GA-ALT
07-591-GA-AAM

FILE DATE: 3/7/2008

SECTION: 2 of 2

NUMBER OF PAGES: 215

DESCRIPTION OF DOCUMENT: Transcript
Volume I Exhibits

EXHIBIT

COMPANY
39

nrri

Decision-Making Strategies for Assessing Ratemaking Methods: The Case of Natural Gas

The National Regulatory Research Institute

September 2007

07-10

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EXECUTIVE SUMMARY

The ratemaking process is complex and interactive, involving groups with different goals, interests and agenda. It also entails addressing a number of objectives, each of which has a distinct effect on the public interest. Different ratemaking options, which over the past few years gas utilities have proposed before their state commissions, also have varying propensities to advance those objectives, with the usual situation where one option would advance some objectives while impeding others. A systematic approach to ratemaking should result in more transparent, effective and consistent decisions. It can help to elevate the scientific aspect of ratemaking by combining objective and subjective information more formally. The public interest stands to benefit from this approach.

In reviewing different ratemaking proposals, state commissions should have access to unbiased information for helping them better understand and evaluate the consequences of a decision. To make an assessment of ratemaking proposals, commissions should follow three steps. First, commissions need to define the public interest by identifying the multiple objectives that comprise the public interest, assigning weights to those objectives and resolving the trade-offs among them. Second, commissions need to understand each ratemaking proposal fully in terms of how it advances or impedes the multiple objectives that comprise the public interest. Third, commissions need to use a logical, transparent decision-making process, such as multi-criteria decision analysis (MCDA), that selects or modifies ratemaking proposals that come closest to achieving the public interest, as defined by a commission. MCDA can improve regulatory decisions by making more explicit the relationship between different ratemaking mechanisms and the public interest. It allows a state commission to assess proposals systematically, based on both unbiased and subjective information. Under this approach, prior to a utility proposal, a commission would have enunciated its ratemaking principles and objectives in a public proceeding.

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Acknowledgements

The author would like to thank Mr. Ray Blatter, Rate Case Team Leader, Pacific Gas and Electric; Mr. Bob Gray, economist, Arizona Corporation Commission; Dr Ross Hemphill, consultant, Freeman, Sullivan & Co.; Dr. Hethie Parmesano, Senior Vice President, NERA; and Ms. Jane Steinhauer, Director of Natural Gas, Indiana Utility Regulatory Commission, for their comments on earlier drafts of this paper. Special thanks go to the NRRI Director, Mr. Scott Hempling, for his insightful comments and suggestions, which helped to refine the paper. Any errors remain the responsibility of the author.

I. Introduction

The purpose of this paper is to assist state commissions in assessing the public-interest effects of existing and new ratemaking methods.[1] The paper presents decision-making strategies that state commissions can apply to make this determination when encountering existing and new ratemaking methods proposed by utilities and other parties.

This paper uses a case study of recent ratemaking proposals by natural gas utilities. These utilities have requested their commissions to approve new ratemaking proposals, which in some instances represent significant departures from traditional practices. These new proposals challenge state commissions to make rational, systematic and transparent decisions in an environment where commissions must abide by standard legal requirements in setting rates in addition to accounting for policy-based objectives.

A major conclusion of this paper is that state commissions should articulate their objectives for ratemaking and place weights on those objectives. The merit of a ratemaking method depends upon how well it advances the totality of regulatory objectives compatible with the public interest. In the real world, the practice of ratemaking requires a commission to trade-off multiple objectives, some of which conflict. These objectives and their relative importance also change over time, warranting commissions periodically to revisit their longstanding ratemaking practices.

State commissions can apply different strategies to assess new ratemaking proposals. Decision-making involves choosing *the best solution to a problem* from among a number of options. A good decision-making process involves identification of the problem, developing and analyzing alternative options, choosing and implementing the best option, and evaluating the decision quality based on the results.

In reviewing different ratemaking proposals, state commissions should have access to unbiased information for helping them better understand and evaluate the consequences of a decision. To make an assessment of ratemaking proposals, commissions should follow three steps. First, commissions need to define the public interest by identifying the multiple objectives that comprise the public interest, assigning weights to those objectives and resolving the trade-offs among them. Second, commissions need to understand each ratemaking proposal fully in terms of how it advances or impedes the multiple objectives that comprise the public interest. Third, commissions need to use a logical, transparent

[1] Ratemaking involves three distinct steps: (1) the determination of a utility's annual revenue requirements recoverable from customers, (2) the allocation of the total costs to each customer class or services, and (3) the creation of a rate design that will collect those costs.

decision-making process that selects or modifies ratemaking proposals that come closest to achieving the public interest, as defined by a commission.

Rate designs and cost allocations can produce results that conflict with market realities and underlying regulatory objectives. These consequences can undermine the societal benefits of regulation by producing outcomes that lie contrary to the public interest. Both regulators and public utilities recognize the negative outcomes from faulty ratemaking, although they disagree over the definition of "faulty." A public utility may perceive faulty ratemaking as the cause of revenue insufficiency and excessive risk allocation to company shareholders; regulators, on the other hand, may view faulty ratemaking as the cause of undue price discrimination, unfair risk shifting of certain costs to consumers, and loud complaints from consumers.

In their review of ratemaking proposals, state commissions should assume that regulatory objectives differ from utilities' objectives. If both public utilities and state commissions have the same objectives and rank them similarly, regulation would have a lesser role in setting rates, as the "invisible hand" of the marketplace could then be trusted more to guide a utility's actions toward the public good. But, almost always, utilities and commissions not only disagree over which objectives are relevant for ratemaking but also over the relative importance of each one.

II. The standard requirements for "just and reasonable" rates and policy-based objectives

A. Standard requirements

Most state commissions operate under the legislative and judicial mandates that they set "just and reasonable" rates for public utilities. These mandates reflect standard legal requirements imposed by court interpretations of statutes and of the Constitution. Although interpreted differently by regulators, just and reasonable rates typically have the following four features:

1. They reflect the costs of an efficient or prudent utility.

2. They reflect the cost of serving different customer classes and of providing different services and different levels of services.

3. They allow the efficient or prudent utility a reasonable opportunity to earn a return sufficient to attract new capital.

4. They avoid undue discrimination against any customer class (or customers within a class) or service (e.g., rates should not fall below short-run marginal cost).

The first standard requirement of "just and reasonable" rates prevents customers from paying for costs that the utility could have avoided with efficient or prudent management.[2] Regulators attempt to protect customers from excessive utility costs by scrutinizing a utility's costs in a rate case or by applying an incentive mechanism (with explicit rewards and penalties) that motivates a utility to act efficiently. Ratemaking practices can affect the propensity of a utility to act efficiently. Cost riders, where certain costs do not undergo a thorough review by the commission, may weaken a utility's incentive to control those costs, all else equal.

The second standard requirement, which involves a cost-of-service study, allocates costs to various customer classes and utility services.[3] The cardinal principle underlying cost allocation is that customers and services should bear those costs that they cause.[4] Although state commissions pay attention to cost-based principles, they often deviate from these principles in setting rates.[5] The reason for considering non-cost factors is that a commission has different public-policy and ratemaking objectives that cause it to depart from cost-based principles. A commission might feel that rates below fully allocated cost to low-

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[2] Axiomatically, the prudence test requires only reasonableness under the circumstances at the time that a utility made a decision or undertook an action; the test excludes consideration of later facts.

[3] A cost-of-service study can define cost as either embedded cost or marginal cost. Embedded cost represents a cost actually incurred by a utility, sometimes referred to as original cost, historical cost or accounting cost. Marginal cost is a forward-looking cost that accounts for the cost of a utility in providing an additional unit of service. See the Appendix for a more compete definition.

[4] This allocation results in the utility earning similar rates of return across customer classes and services.

[5] Many commissions consider cost-of-service studies as guides to setting rates, but not the only source of information or guidance. These studies incorporate judgment and apply imprecise data (e.g., load research). In addition, cost-of-service studies tend to equate rates of return across classes of customers, without accounting for differences in the risk to the utility of serving different customer groups. These studies may also conflict with other regulatory objectives and public policy goals.

income households, or subsidies to promote energy efficiency, are compatible with its goal to serve the public interest.

The third standard requirement permits the utility an opportunity to recover the costs (including its cost of debt and equity[6]) contained in the rates approved by the regulator in the last rate case. A regulator generally sets rates so that a utility has an opportunity to earn a fair or reasonable rate of return for shareholders, assuming efficient and economical management; but the regulator does not guarantee that return. A frequent area of contention in rate cases is the interpretation of "opportunity."[7]

The fourth standard requirement, while allowing some forms of price discrimination, prevents other forms (i.e., undue discrimination) where, for example, prices for some services are set below incremental costs or favorable price treatment to some customers pushes up rates to other customers. Price discrimination is more socially justified when it leads to a net increase in sales and increased welfare for consumers as a whole, but undesirable when most of the economic gains pass to the firm and total sales by the firm drop.[8] State commissions have authorized discriminatory pricing when it serves some public interest, such as economic development and the deterrence of uneconomic bypass.[9]

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[6] A utility's cost of equity corresponds to the more common term "normal profits." Both terms account for the cost a utility must incur to attract funds from shareholders. When shareholders invest in a utility, their normal return represents an opportunity cost since they forego earning normal returns in other firms by investing in the utility.

[7] A dictionary definition of opportunity relates to the term "good chance." The reader can see readily how different stakeholders can interpret this term to serve their own interest.

[8] The economics literature has shown that, where price discrimination increases total sales, it generally improves economic efficiency as well as the economic welfare of consumers as a whole. Otherwise, when total sales do not increase, the outcome is often higher profits for the selling firm but lower overall well-being for consumers. See, for example, W. K. Viscusi et al., *Economics of Regulation and Antitrust, 2nd edition* (Cambridge, MA: The MIT Press, 1995), Chapter 9.

[9] Historically, state commissions have approved a form of discriminatory pricing for some customers of gas utilities, namely, value of service pricing. Value of service pricing means pricing service to different customer groups based on the value each group places on the service. This pricing method is distinguished from "average pricing," in which customers of a particular grouping pay the same average price for a service regardless of the value it places on that

State commission-enabling statutes often direct commission to establish rates that are "just and reasonable." State commissions find this phrase difficult to interpret. Many views of "just and reasonable" exist. What is "just and reasonable" to one group, other groups may find otherwise. A common definition of "just and reasonable" relates to the setting of rates for different classes of customers and services based on the embedded cost-of-service (i.e., the costs incurred by a utility in serving different customer groups and in providing specific services).[10] A regulatory definition often applied is that all customers in a homogeneous class should pay the same rate.[11] "Just and reasonable" also typically entails no cross-subsidies in that no rate to any class of customer or service should result in negative earnings for the utility (i.e., rates that do not lie below a utility's short-run avoided or marginal cost, with negative earnings either absorbed by the utility's shareholders or compensated by other customers). "Just and reasonable" also applies to the opportunity for a utility to cover its prudent costs, including a rate of return, sufficient but no higher than necessary, to attract prospective investors.

B. Policy-based objectives

A review of state commission decisions in a large number of rate cases over time reveals at least eight policy-based objectives of ratemaking that commissions have exercised over time. These objectives reflect policy judgments made within the legal parameters established by statutory language and court decisions:

1. **"Public acceptability"** refers to how the consumers, the public and political actors will respond to the new rates resulting from a commission's decision. Commissions like to avoid negative public reaction to their decisions, as this places them in an unfavorable light and more likely would trigger

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service. In the mid-1980s several gas utilities turned to value of service pricing, which set rates below embedded costs but no lower than long-run marginal cost, to maintain industrial load that would have otherwise switched to oil. Most often, these rates were set at (or near) competitive prices for alternative fuels to protect utility ratepayers from the effects of "too deep" discounts.

[10] In a typical cost-of-service study, the goal is to allocate revenue responsibly such that utility would earn the same rate of return on the share of rate base allocated to each class of customer or service.

[11] The term "horizontal fairness" refers to the equal treatment of similar customers -- for example, customers imposing the same cost on a utility should face the same rate. Another notion of fairness, "vertical fairness," is the unequal treatment of dissimilar customers – for example, two customers imposing different cost on a utility should face different rates.

legislative intervention. Public acceptability should result in minimal customer complaints, legislative intervention and negative media publicity.

2. **"Rate stability and gradualism"** means that new rates and the methods used to determine them have some historical coherence. Especially troublesome are new rates that increase unexpectedly and are well above previously rates for particular classes of customers.

3. **"Equity or fairness"** is an elusive and contentious term that is the subject of heated debate in ratemaking proceedings. This term applies both to the regulatory treatment of different classes of customers, relative to each other, as well as to the treatment of utility shareholders relative to customers. This objective usually requires rates that are not "arbitrary or capricious," an allocation of business risk between a utility and its customers that matches risk with reward, and allocation of costs across customer classes based on cost-causation principles.

4. **"Affordable utility service"** means that almost all customers can afford utility service that satisfies essential energy and other needs. Meeting this requirement may require the utility to offer discounted rates to low-income households. For many low-income households, paying their utility bills under an unsubsidized rate may mean sacrificing the purchase of other commodities and services essential to their economic well-being. Funding of the subsidized rates would come from other customers.[12]

5. **"Efficient consumption"** means that consumers face prices for utility service that reflect cost of service, thereby inducing consumers to act efficiently. Below-cost prices result in wasteful use of utility service, while above-cost prices result in too little usage.[13]

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[12] Whether state commissions and utilities should concern themselves with the unaffordability of utility service to low-income customers is an issue that has permeated public utility regulation for decades. Many public policy analysts have argued that the real problem is certain households having inadequate incomes to pay for their essential goods and services. (This problem worsens for low-income households consuming energy, since they generally have low energy-efficient appliances and poorly insulated homes.) They contend that state and federal legislatures, or other governmental entities, should address this social ill by supplementing the income of poor households and by offering them financial support for energy-efficiency improvements, which would be more effective and efficient than subsidizing the prices they pay for utility service.

[13] This "efficient consumption" objective does not necessarily coincide with the objective of promoting what is commonly called "energy efficiency." Energy efficiency measures the ratio of energy input (e.g., therms of natural gas) and output (e.g., comfort). This term differs from the concept of economic efficiency, which accounts for both physical inputs and outputs and their societal value, usually expressed in dollars. Promoting energy efficiency per se may

6. **"Efficient competition"** refers to the utility and its competitors (e.g., retail marketers) having equal opportunities to compete for customers. Pricing of utility services plays a crucial role in determining whether this condition holds. When a commission fixes the prices of the local utility at embedded cost, for example, retail marketers can attract customers of the utility even when they are less efficient, because they have more pricing flexibility than the local utility. Efficient competition usually results in no uneconomic bypass and favoritism toward a utility affiliate.

7. **"Moderate regulatory burden"** refers to the objective of a commission to avoid frequent future rate cases. Rate cases absorb significant commission staff resources and time, diverting those resources from other commission activities.

8. **"Promotion of specified social goals"** means that a commission might want to pursue objectives that lie outside the normal mainstream of regulation. A commission might feel strongly about promoting energy efficiency in an environment of high gas prices, or about the increased unaffordability of gas service to low-income households. In achieving these objectives, a commission would approve special rates that deviate from traditional ratemaking principles (e.g., economic development rates that lie below embedded cost but above long-run marginal cost.)

The relative weights placed on different ratemaking objectives vary across state commissions, and shift over time in response to economic and political forces. During the 1980s and early 1990s, bypass of large customers from the local gas distribution system – i.e., customers buying a gas service directly from pipelines or installing their own spur line connected to the main pipeline, thereby

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lower economic efficiency in that the benefits of increasing energy efficiency may fall short of the additional costs.

Economic efficiency takes into account: (1) the cost to society from satisfying the demands of utility consumers (i.e., productive efficiency) and (2) the value that consumers place on utility service (i.e., allocative efficiency). The keys to achieving economic efficiency are to set rates based on marginal cost principles and to give utilities strong incentives to operate efficiently. Economic efficiency helps to avoid the waste of resources from both consumption and production. Economic efficiency involves maximizing total net economic value, while equity or fairness involves the distribution of net value among producers and consumers. Another way to look at the two concepts is that what matters to economic efficiency is maximizing the size of the pie, while equity or fairness cares about the slicing of the pie. Ratemaking involves treating these two concepts interdependently as maximizing the size of the pie requires efficient pricing to consumers, which therefore encompasses slicing the pie at the same time.

leaving the local utility unable to recover its fixed costs – was a major concern for both gas utilities and state commissions. The commissions responded by approving special discounted rates, even though they were discriminatory in nature, to avoid the revenue loss resulting if these customers bought their gas directly off the interstate pipeline.[14] Competition between natural gas and oil in the industrial sector during the early and mid 1980s placed pressure on state commissions to offer special (i.e., value of service) rates to large customers with fuel switching capability. Since the rise of natural gas prices in 2000, several commissions have paid more attention to energy efficiency by encouraging or requiring gas utilities to spend more money on, and engaging more actively in, promoting cost-effective energy conservation. This increased emphasis by regulators on energy efficiency has permeated the debate over proper rate design. As another recent issue, gas utilities have argued that traditional ratemaking has jeopardized their ability to earn sufficient revenues in view of the continuous decline in gas usage per customer.

III. Ratemaking methods and trade-offs among regulatory objectives

A. The standard two-part tariff

This section starts out by reviewing the salient features of traditional ratemaking for gas utilities. The discussion focuses only on the two-part base rate (i.e., the non-gas component of retail rates), which has received much scrutiny in recent years.[15, 16] The two-part tariff evolved during the early 20th century to

[14] These special rates were in response to the shortcomings of strict embedded-cost pricing in a competitive marketplace where consumers are able to switch providers and utilities lack absolute monopoly power. Many commissions approved special rates (with the condition that they at least cover marginal cost), fearing that if they did not, a utility's profits would fall and, ultimately, remaining customers would end up with higher rates, because a departing customer would no longer be contributing to the utility's fixed costs.

[15] Since 2000, the non-gas component of retail prices has declined proportionately because of the rise in wholesale gas prices. For many gas utilities, the non-gas component represents about 20-30 percent of the retail price.

[16] For all states (except for Hawaii), the utility recovers its purchased gas costs through some automatic adjustment mechanism. In most states, the utility passes through dollar-for-dollar purchased gas costs subject to a prudence review. The ex post facto review typically applies a rebuttable-presumption-of-prudence standard whereby parties contesting prudence must provide evidence of unreasonable conduct by the utility at the time of gas purchasing without the benefit of hindsight. A number of gas utilities have a cost-sharing incentive

replace the one-part tariff where the gas utility recovered all of its costs in a volumetric charge. Gas utilities and state commissions supported the two-part tariff as a way to increase consumption, reduce average cost, and generate sufficient revenues to recover fixed costs.[17]

1. Description of the standard two-part tariff

Traditional gas rates must recover the cost of gas sold plus the cost of building, maintaining and operating the gas utility system. In this discussion, we will set aside the portion of rates related to the cost of gas sold, and focus on the remaining costs. These remaining costs comprise what is normally called the "base rate." This base rate, in traditional ratemaking, is charged by means of a two-part tariff. The following arithmetical expression shows the standard two-part tariff for base rates set by gas utilities:

$$B_i = C + p \cdot q_i,$$

where the base rate for customer i (B_i, reflecting all non-gas costs) equals the sum of two components: the customer charge (C) applicable to all customers, and the volumetric distribution charge (p) times the quantity of gas consumed by customer i (q_i).[18]

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mechanism that allows a utility to profit from exceptional gas-procurement performance and to absorb some of the costs from sub-par performance. (See K. Costello and J.F. Wilson, *A Hard Look at Incentive Mechanisms for Gas Procurement*, NRRI 06-15, November 2006.) Some state commissions recently have reviewed the existing automatic adjustment mechanisms in response to volatile wholesale gas prices. Commissions have tended to adjust rates more frequently, in some instances going from an annual or semi-annual adjustment to a quarterly or monthly adjustment. Reasons for this change include reducing the financial burden on the utility and avoiding a large sudden increase in prices to consumers, both of which stemmed from high and volatile natural gas prices.

[17] The old one-part tariff structure had several problems. It resulted in (1) revenue instability for the utility, (2) poor (economically inefficient) price signals for customers, (3) failure to reflect higher cost to the utility for serving lower-usage customers, and (4) unfairness to high usage customers relative to low usage customers. Notwithstanding these negative outcomes, this rate design was an improvement over its predecessor, the unmetered fixed monthly bill (e.g., a customer pays $50 per month so matter how much gas she uses).

[18] The formula above assumes a uniform volumetric distribution charge regardless of the volume consumed. Many gas utilities have block pricing where the volumetric distribution charge varies between blocks of consumption. One common rate design is the declining-block structure, which in recent years has fallen out of favor because it encourages additional gas consumption. Declining-

The base rate recovers those costs related to investment in, and operation of, a gas transmission and distribution system. The customer charge typically includes the direct cost of serving a customer, including the cost for meters, meter reading, billing and collection, servicing an account, call centers and other costs independent of gas usage.[19] The volumetric transmission and distribution charge recovers the remaining non-gas costs of a utility. It includes both operating costs and capital costs not recovered in the customer charge.[20]

Using a numerical example, assume that the monthly customer charge is \$10, the volumetric distribution charge is \$1.50 per thousand cubic feet (Mcf) and monthly usage is 10 Mcf. Under this tariff structure, the customer's bill (excluding purchased gas cost) would be \$10 + (\$1.50·10), or \$25. If the customer did not consume any gas during the month, she would be charged \$10. The marginal price to the customer, i.e., the cost to the customer of consuming one additional Mcf of local distribution service, would be \$1.50. Under prevailing rate structures, the marginal price exceeds the marginal cost to the utility, since the marginal price includes fixed costs. A secondary outcome is that the average price of gas to the customer (i.e., the customer's bill divided by monthly usage) decreases as the customer consumes more gas. In the example, the average price to a customer using 10 Mcf would be \$2.50 per Mcf, while the average price at a usage level of 15 Mcf would be \$2.17 per Mcf. This decline in average price reflects the decrease in a utility's average costs as monthly consumption increases, because the fixed costs of the system (to the extent they are recovered through the non-varying customer charge) are divided by more units of sale.

2. Consequences of the two-part tariff

Gas utilities using the two-part rate structure recover much, if not most, of their fixed costs in the volumetric charge, which not only makes the rate structure economically inefficient but also incompatible with some of the other regulatory

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block rates, however, have the benefits of providing a utility with earnings stability (by allowing it to recover its fixed costs in the lower-usage blocks) and of promoting economic efficiency when it sets tail-blocks charges at or close to marginal cost. (Economic efficiency requires only that the pricing of the unit of service consumed at the margin corresponds to marginal cost – not that all units of service do.)

[19] The monthly customer charge equals the allocated annual customer costs divided by the number of customer months.

[20] The volumetric distribution charge equals the distribution costs (minus the costs recovered in the customer charge) divided by the annual sales as determined at the last rate case.

objectives. One reason for this practice is that regulators as a rule disfavor high monthly customer charges, which would result from reallocating fixed costs from the volumetric charge to the customer charge. For many gas utilities, over 90 percent of their non-gas costs reflect fixed costs, with the majority of those costs typically recovered in the volumetric charge. As discussed next, problems arising from this allocation include under-recovery (or over-recovery) of a utility's prudent fixed costs and disincentives for a utility to promote energy efficiency.

The standard two-part tariff, as currently applied by most gas utilities, has several consequences. First, the recovery of some of the utility's fixed costs – other than the fixed costs recovered through the customer charge – depends upon the level of gas usage. When usage falls (or rises), because of factors such as abnormal weather, the business cycle, changes in customer behavior, and appliance and building characteristics, a utility's earnings also fall (or rise) because the utility must pay the fixed costs regardless of the revenue level. Where recovery of a large percentage of the fixed costs depends upon usage, a small change in usage can have a large effect on earnings. One consequence of linking fixed-cost recovery to usage is that the utility becomes riskier in the eyes of prospective investors and its cost of capital increases.

Second, because earnings fall with lower usage, the utility has a disincentive to promote energy conservation. If the volumetric charge includes only variable cost, then a drop in sales reduces costs and revenues proportionately, with no effect on earnings. This outcome would reduce any utility disincentive, at least between rate cases, to promote energy conservation.

Third, high usage customers bear a disproportionately higher share of fixed costs than low usage customers, even though much of these costs are more customer-related than usage-related. Examples of such costs, i.e., fixed costs recovered through the volumetric rate rather than through the customer charge, include the capital costs for distribution mains. Recovery of fixed costs also occurs lopsidedly during the winter or peak season when consumption is highest, which aggravates the problem of customers having high winter gas bills.

Fourth, the gas utility finds it more difficult to compete with alternative energy providers for large customers (e.g., oil retailers selling to industrial customers) because of the relatively high marginal price for gas delivery service. For high usage customers, a lower marginal price would reduce their total gas bills relative to a rate structure that allocates more of a utility's fixed costs to the volumetric charge.

Fifth, because the volumetric distribution charge includes fixed costs, the tariff is economically inefficient. Customers would tend to under-use gas since the marginal price includes fixed costs.[21] Ideally, from an economic-efficiency perspective, at the margin customers would pay a usage price equal to marginal cost.

Last, the incremental change in a customer's gas bill from increased usage (for example, because of cold weather) would be greater than if the usage charge excluded all fixed costs. This outcome would tend to cause gas bills to fluctuate more, especially for residential customers during the winter months.

B. New proposed ratemaking practices

1. Motivations

As of early March 2007, thirty-one investor owned gas utilities had rate cases pending before state public utility commissions. In 2006, state commissions decided rate cases for twenty-four gas utilities. These utility proposals encompass both the cost recovery and rate-design aspects of rate setting. Many of these proposals involve new practices reflecting changes in market conditions for natural gas as well as in regulatory and energy policies.[22] The major changes include:

1. The recent shift in policy by many state public utility commissions to encourage gas utilities to promote energy efficiency

2. Increased risk to gas utilities from higher gas prices causing a proliferation of bad debt expenses while simultaneously decreasing demand

3. Additional capital requirements caused in part by new safety regulations and the need to replace aging distribution mains (e.g., cast iron steel pipes)

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[21] Some readers might argue that although the price signal *per se* would cause customers to under-consume, non-price factors (e.g., information and capital-market barriers, externalities) would lead to customers under-spend on energy conservation. The poor price signal provided by the standard tariff, according to this view, would therefore counteract those barriers and represent a second-best solution. A preferred solution would be to address directly the non-price factors impeding economically efficient energy conservation.

[22] In recent years, electric and water utilities have also filed new rate designs and cost-recovery mechanisms, partially because of rising prices and an increased emphasis on reducing electricity and water usage.

4. Shifting regulatory priorities on the underlying objectives of ratemaking, including the need to assist low-income households and mitigate against high gas-bill volatility

The recent ratemaking proposals reflect the view of some gas utilities and other stakeholders that existing ratemaking practices, especially the longstanding reliance on the two-part tariff discussed in Part III, warrant revisiting because of changed market conditions and public-policy goals.[23] The natural gas industry has undergone fundamental changes in just a few years. First, wholesale gas prices have become more volatile and difficult to predict, and have reached much higher levels than 1990 prices. Although almost all gas utilities have purchased gas adjustment mechanisms to shift to consumers the risks of these market dynamics, consumers have expressed a preference for price stability and have cut back on their gas usage. Recent evidence has shown that customer demand response to higher gas prices have intensified over the last two years.[24]

Second, regulators and energy policymakers have intensified their efforts to promote energy efficiency, with gas utilities expected to play a more active role. Several state commissions have committed to implementing the National Action Plan for Energy Efficiency (www.epa.gov/solar/actionplan/report.htm), which affects both electric and gas utilities. A key recommendation of the Plan emphasizes the importance of ratemaking in aligning utility incentive with energy efficiency. Other state commissions have initiated proceedings to determine whether, and how, gas utilities should become more active in promoting energy conservation.

Third, high gas prices have aggravated the affordability problem for low-income households. Low-income households spend a much higher percentage of their incomes on natural gas than other households do. Partially because of the increased unaffordability of gas service to poor households, more customers have become delinquent in paying their gas bills, resulting in lost revenues to utilities that they did not anticipate at the time of the last rate case.

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[23] Over the past decade, both regulated and unregulated industries have undergone radical shifts in pricing practices. Internet service and telecommunications service are prime examples of this phenomenon. Numerous other examples exist for a wide range of industries where changes in market dynamics have led to new pricing practices.

[24] Some gas utilities have reported a sharper decline in gas usage per customer (normalized for weather) over the past two years than in the previous 20-25 years. One study concluded that non-price factors like new building codes and appliance efficiency standards have contributed to the downward trend of gas usage per customer over the past several years. (See Frederick Joutz and Robert P. Trost, *An Economic Analysis of Consumer Response to Natural Gas Prices*, prepared for the American Gas Association, March 2007.)

Fourth, because of high gas price volatility, hedging has become more important. Hedging activities by a utility in both its gas purchasing and ratemaking practices can help to stabilize customers' gas bills.

In sum, new ratemaking proposals stem mainly from the direct and indirect consequences of high natural gas prices since 2000. (See Table 1) Higher prices have increased risk to both utilities and their customers, calling into question the efficacy of prevailing ratemaking methods to promote the public interest in view of today's market and public policy environment.

Table 1: Consequences of High Natural Gas Prices

• Fewer households find natural gas affordable
• Energy conservation becomes more beneficial
• Fuel-switching becomes more imminent
• Price elasticity effect becomes more pronounced
• Bad-debt expenses increase
• Both the utility and its customer generally face more risk
• Hedging becomes more important from both the utility and customer perspective
• Utility customers become less satisfied with their utility service and regulatory oversight
• Overall, the gas industry becomes less stable with usage levels, gas bills and utility earnings more volatile and uncertain

2. New ratemaking proposals

A key issue in recent gas rate cases is whether the continuation of traditional ratemaking practices will allow a utility a reasonable opportunity to earn its authorized rate of return in light of the changes in the market environment and public policy, as discussed above. With several gas utilities arguing that traditional practices will not, they have proposed new cost and revenue riders in addition to new rate designs.

A list of new ratemaking proposals includes:[25]

- Rider for revenue deviations from some baseline level;[26] hereafter, this paper refers to this mechanism as a revenue decoupling (RD) rider[27]

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[25] The Appendix describes some of these ratemaking mechanisms.

[26] The generic term "revenue decoupling" refers to the separation of a utility's earnings from actual sales. Under this definition, revenue decoupling

- Straight fixed-variable (SFV) rate design, where the utility shifts all the fixed costs, both customer and demand related, out of the volumetric charge to a fixed charge such as the customer charge or demand charge

- Earnings sharing mechanism (or sometimes referred to as a return stabilization mechanism) where periodic adjustments, usually annually, occur when the utility's actual rate of return on equity falls outside some pre-determined band[28]

- Rider for bad debt[29]

- Rider for pipeline integrity management

- Rider for pipeline replacement costs

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includes riders, specific forms of declining-block rate structures, and a SFV rate design where the utility recovers all of its fixed costs in a non-usage charge.

[27] Under RD riders, actual revenues correspond to the utility's revenue requirement, as determined in the last rate case, with rate adjustments made between rate cases as sales volumes deviate from the predetermined baseline level (e.g., weather-normalized usage per customer). In contrast, under traditional ratemaking, the utility's revenues change as sales volumes vary. With revenues more stable under a RD rider, the utility's actual earnings would deviate less from the level established during the last rate case. One misperception is that a RD rider would guarantee that a utility earns its authorized rate of return between rate cases. RD riders reconcile revenues, not costs. Unexpected cost increases (or decreases) and fewer (or more) new customers than expected would cause actual return on equity to deviate from the expected return. A RD rider, however, would increase the likelihood of a utility earning its authorized rate of return.

[28] Gas utilities have argued, among other things, that earnings sharing would extend the time between general rates cases, better link rates to more current information on costs and sales, and keep the commission current on the financial condition of a utility.

[29] Most of these riders involve recovering the gas cost portion of bad debt expense in the purchase gas adjustment (PGA) mechanism. Utilities proposing these riders have argued that their bad debt has increased significantly over the past few years because of the combination of high gas commodity prices and more customers falling further behind in paying their gas bills. They conclude that the practice of recovering bad debt as a fixed expense in base rates is no longer appropriate.

- Rider for pension costs
- Rider for energy efficiency or demand-side management costs
- PGA-like mechanism that tracks under and over recovery of a utility's fixed costs (i.e., fixed cost balancing accounts) with periodic fixed cost true-ups between rate cases

The new ratemaking proposals largely attempt to stabilize utility revenues and to allow recovery of certain costs outside a rate case review. They reflect the view that the longstanding use of a test year (i.e., a twelve-month period chosen to calculate the required revenue to recover a utility's distribution non-gas costs) to measure certain costs and gas sales for the rate-effective period is no longer appropriate. The basic argument made by proponents of new ratemaking methods is that events in the natural gas sector have made costs and sales difficult to predict and unstable. Even with modification to historical costs and sales for "known and measurable" changes, according to this argument, a gas utility would still face high risk, reducing its ability to earn its authorized rate of return.

The concern by gas utilities over revenue stabilization stems from what they see as the asymmetrical distribution of sales around some baseline or normalized level of sales. That is, they perceive the probability of actual sales falling below some baseline level set by a commission in a rate case to exceed the probability of actual sales exceeding the baseline level. A major argument for this view is that commissions generally determine base rates assuming no continuation of a decline in gas usage per customer. Gas utilities have argued that this assumption is contrary to statistically based predictions and past trends.[30]

Most of the new ratemaking proposals by gas utilities involve the use of trackers or riders to allow the utility to adjust its rates outside of a rate case.[31]

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[30] Gas utilities in several rate cases have shown a decline in usage per customer over the past two decades. Although parties to these proceedings generally have not disputed this phenomenon, some have questioned whether this decline will continue in the future. Reduced consumption per customer does not imply that utilities' total gas sales to residential customers will fall in the future. (See Energy Information Administration, *Annual Energy Outlook 2007*, February 2007 and other projections.) Most studies expect moderate growth in total residential sales over the next several years, even in view of a continued decline in sales per residential customer (with growth varying by state and region). These projections call for utilities' revenues from residential sales to grow between rate cases because of the addition of new customers offsetting a decline in use per customer.

[31] Trackers or riders refer to a mechanism that allows a utility to adjust its rates without having to file a formal rate review, although any resulting rate

For the past thirty years, state commissions have allowed utilities to recover changes in their purchased gas costs through a rider-type mechanism, commonly called a PGA mechanism. Some commissions have also permitted gas utilities to recover other costs, for example those related to energy efficiency activities, outside of a rate case.

Commissions generally frown upon pass-through of costs outside of a rate case (even when subject to a prudence review) unless extraordinary circumstances exist. Commission decisions have focused on whether to pass through costs, and make rate adjustments for unexpected changes in sales, outside of rate case review in light of the possible downside consequences.[32]

Historically, commissions apply a three-part test in judging the merits of a rider or tracker. The three-part requirement for commission approval of riders and trackers typically include: (1) the cost or sales activity must lie outside the control of the utility, (2) variations in outcomes can have a material effect on utility earnings, and (3) the activity is difficult to predict.

The reluctance of commissions to approve riders and trackers mainly lies with their effect on shifting risk to consumers and on diminishing regulatory lag. Regulatory lag refers to the time gap between when a utility undergoes a change in cost or sales levels, and when the utility can reflect these changes in new rates. Economic theory predicts that the longer the regulatory lag, the more incentive a utility has to control its costs. The reason is that when a utility incurs costs, the longer it has to wait to recover those costs, thus the lower its earnings become. Consequently, the utility would have an incentive to minimize additional costs. Commissions rely on regulatory lag as an important element in motivating utilities to act efficiently. Regulatory lag is a less than ideal method, however, for

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changes usually receive some level of regulatory oversight. These rate adjustments can occur because of the incurrence of special costs or the realization of sales departing from some predetermined baseline level. This mechanism is generally only applied under unusual circumstances. Some state commissions approving cost trackers place a cap on the amount recovered through the mechanism, with costs above the cap deferred for later recovery.

[32] Prior to the recent interest in revenue decoupling, rate adjustments for sales focused mostly on weather normalization adjustments (WNAs). The mechanism adjusts customers' monthly gas bills, usually during the winter heating season, to reflect weather patterns commensurate with "normal weather." The rationale for WNAs centers on the effect of the traditional ratemaking practice to cause earnings to fluctuate based on actual sales. Twenty-seven state commissions currently allow at least one gas utility to use a WNA mechanism. (See K. Rogers, "Revenue Decoupling: Trend or Transitions," presented at the Mid-Atlantic Conference of Regulatory Utilities Commissioners Annual Convention, June 5, 2007.)

rewarding an efficient, and penalizing an inefficient, utility. Some of the additional costs may fall outside the control of a utility (e.g., increase in the price of materials), and any cost declines may not relate to a more efficient utility (e.g., deflationary conditions in the general economy).

C. Trade-offs among objectives

1. Challenges for state commissions

The new ratemaking proposals advance some regulatory objectives while impeding others. The challenge for regulators is to weigh these objectives and measure (if possible) the effect of a ratemaking mechanism on each specified objective. Assigning weights requires judgment by the regulator, while examining the effects demands analytical skills supplemented by data and other unbiased information.

Table 2 shows how specific ratemaking practices (described in the Appendix) can have both positive and negative effects on different regulatory objectives. Stakeholders have proposed these practices before state commissions, who have either approved them or rejected them.[33] (The author used his best judgment, applying economic analysis and available empirical evidence, in determining the effects of each ratemaking practice on either advancing or hindering individual objectives. Some readers may rightly disagree with these assessments.)

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[33] This paper discusses some of these ratemaking practices. In the Appendix to this paper, the reader can find a brief description of each ratemaking practice; other publications contain more detailed descriptions. (See, for example, NARUC Subcommittee on Gas, *Gas Distribution Rate Design Manual*, 1989; American Gas Association, *Gas Rate Fundamentals*, 4th Edition, 1987; and M. Harunuzzaman and S. Koundinya, *Cost Allocation and Rate Design for Unbundled Gas Services*, NRRI 00-08, May 2000, available at www.nrri.ohio-state.edu).

Table 2: Ratemaking Practice and Trade-offs Among Objectives

Ratemaking Practice	Objective(s) Advanced	Objective(s) Hindered
Standard Two-Part Tariff	Public acceptability, fairness in risk sharing	Efficient price-driven gas consumption, revenue and earnings stability, promotion of utility-initiated energy efficiency
Revenue-Decoupling Rider	Revenue and earnings stability, neutral utility incentives for the level of gas usage, fairness to the utility in recovering fixed costs	Fair allocation of business risk, public acceptability, efficient price-driven gas consumption
Straight Fixed-Variable Rate	Revenue and earnings stability, efficient price-driven consumption, neutral utility incentives for the level of gas usage, more equitable cost allocation	Equity to low usage customers (many of whom may be low-income), public acceptability; gradualism
Weather Normalization Adjustment	Revenue and earnings stability, winter gas-bill stability	Public acceptability
Inverted-Block Rate	Promotion of customer-initiated conservation, assistance to low-income households	Revenue and earnings stability, allocative efficiency; non-discrimination
Declining-Block Rate	Revenue and earnings stability, improved system utilization (i.e., productive efficiency)	Promotion of price-driven energy conservation, non-discrimination
Cost Rider	Earnings stability, fairness to the utility, fewer rate cases	Robust incentives for cost control (less regulatory lag), fair allocation of risk
Cost-Based Customer Charge	Allocative efficiency, more levelized gas bills across seasons	Public acceptability, equity to low usage customers (many of whom may be low-income)
Flexible Rate	Responsive to competitive and other conditions, improved system utilization (i.e., productive efficiency), avoidance of uneconomic bypass	Non-discrimination, fairness to captive customers
Special Contract	Responsive to competitive and other conditions, improved system utilization (i.e., productive efficiency), avoidance of uneconomic bypass	Non-discrimination, fairness to captive customers
Discriminatory Rate in General	Responsive to competitive and other conditions, improved system utilization (i.e., productive efficiency)	Fairness to captive customers
Rate Based on Marginal Cost Allocation	Price efficiency, improved system utilization (i.e., productive efficiency)	Preciseness of cost data, rate stability, public acceptability
Seasonal Rate	Allocative efficiency, equitable cost allocation across seasons	Affordability, public acceptability
Earnings Sharing	Earnings stability, fewer rate cases, allocative efficiency	Robust incentives for cost control (less regulatory lag)
Targeted Subsidized Rate	Affordability	Allocative efficiency, non-discrimination

The next section of this paper attempts to show alternative strategies (i.e., decision rules) that regulators can apply to assess and compare the public-interest aspects of different ratemaking practices. All of these strategies, in different ways, take into account the underlying objectives of ratemaking, with regard to both their specification and their relative importance. Looking at Table 2, a state commission would find it difficult to rank and compare the ratemaking practices in advancing the public interest without first knowing the relative importance of each objective in addition to the trade-offs involved.

2. Illustrations of trade-offs among regulatory objectives

Ratemaking decisions made by a commission typically have conflicting consequences. That is, the ratemaking method approved advances some particular regulatory objectives while impeding others. The classic example is marginal cost pricing. (Marginal cost pricing sets price equal to the cost to the utility of the last unit of service.[34]) This pricing rule promotes economic efficiency by providing consumers with proper price signals while, some argue, clashing with the objectives of equity and gradualism.

Another example of conflicting outcomes relates to seasonal pricing. (Under seasonal pricing, a gas utility would charge higher rates during the winter months when demand and marginal cost are the highest. For an electric utility, rates would typically be higher during the summer months.) This pricing method has the positive features of giving consumers better price signals, of resulting in a more efficient use of a distribution system's facilities, and of requiring no special meters. Yet, some stakeholders have opposed, and some state commissions have rejected, seasonal pricing, for both the electric and gas industries, because it would cause rates to be higher during periods of peak consumption. The higher utility bill during peak periods would likely meet with public scorn, which it has in some instances, and negative media coverage.

Another example is special contracts to a large industrial customer. These contracts have the attractive features of mitigating uneconomic bypass,[35] of

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[34] Most often, utilities apply marginal cost principles to allocate costs. Once a utility determines the relative marginal costs of serving various customer classes, for example, marginal costs are then scaled to the utility's total revenue requirements. Thus, the actual marginal cost would only equal the utility's cost of service by accident and would not constitute the determining factor in establishing the class revenue requirements used to set rates.

[35] Uneconomic bypass refers to the situation where a customer turns to a non-utility provider for one or more services when the alternative provider has higher total costs but lower prices. It is uneconomic because society incurs higher cost in meeting the demands of a customer. One major cause of uneconomic bypass is the inability of the local gas utility to lower its rates below fully allocated embedded costs, which under certain circumstances (e.g., a utility

responding to competition and of contributing to economic development. Yet, they do reflect discriminatory pricing, which conceivably could force other customers to "fund" these special contracts through higher rates, as these contracts result in the utility recovering less of its fixed costs from the industrial customer than what it recovered previously.[36] Other examples abound where a particular ratemaking practice advances some objectives while hindering others.

Especially in regard to a revenue-decoupling rider and SFV rate design, stakeholders recently have made arguments reflecting the relative importance of different regulatory objectives.[37] For a revenue-decoupling rider, the argument centers on whether circumstances warrant the use of a rider to protect the utility from the possibility of less-than-expected sales. Utilities have argued that in the absence of a rider, they will not have a reasonable opportunity to earn their authorized rate of return. Opponents of a rider have argued that a utility can offset revenue losses from declining usage per customer by adding new customers and improving its productivity.[38] Some opponents of a RD rider also have argued that the downward movement of gas usage per customer in the past does not necessarily constitute a trend that will continue in the future.

Another argument relating to revenue-decoupling riders revolves around the issues of what role, if any, a gas utility should play in promoting energy efficiency and the incentives the utility needs to undertake this activity.

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has a high level of surplus capacity) could far exceed its marginal cost. Another cause of uneconomic bypass is faulty rate design where certain customers within a grouping (e.g., high usage customers within the industrial class) pay more then the utility's cost of serving them and, thus, higher then competitive alternatives.

[36] Although the rates to other customers may be higher than before the special contract, they will be lower than what the rates would have been if the customer had actually bypassed the local utility, assuming the utility's unrecovered sunk costs are assigned to the remaining customers rather than to the utility's shareholders. .

[37] See, for example, K. Costello, *Revenue Decoupling for Natural Gas Utilities*, NRRI 06-06, April 2006 (http://www.nrri.ohio-state.edu/nrri-pubs); and K. Costello, "Revenue Decoupling for Gas Utilities: Know Your Objectives," presented at the Mid-Atlantic Conference of Regulatory Utilities Commissioners Annual Convention, June 5, 2007.

[38] Opportunities to add new customers and improve productivity, of course, would vary from utility to utility. In the Southeast (where electricity rates are low relative to most other parts of the country), for example, gas utilities have seen residential customers switching to electric heat pumps. Thus, for these gas utilities at least, the prospects for adding new customers are dim.

Opponents of these riders have argued that the utility should not involve itself with energy efficiency activities or if it does, a revenue-decoupling rider is still not justifiable.

The issues surrounding SFV rate design are contentious as well. Sometimes proposed to state commissions as an alternative to a RD rider (in terms of its ability to separate earnings from sales), it has met with criticism by commissions and some stakeholders. As Table 3 shows, the reader might expect state commissions to prefer a SFV rate design to a RD rider in view of the dominance of SFV in advancing seemingly important regulatory objectives. Yet, while some commissions have recently approved a SFV rate design, in most states gas utilities have steered away from proposing SFV, knowing well if they did, strong opposition from various sources, including commission staff, would ensue. Instead, gas utilities have more commonly proposed RD riders, with the majority of those proposals approved by state commissions. As discussed in the next section, one possible explanation for this disparate acceptance of these outwardly similar ratemaking mechanisms lies with the high weight commissions assigned to the negative features of SFV. SFV would adversely affect low usage customers, for example, some of whom may consume little gas but under SFV could face a significantly higher monthly minimum charge.

Table 3: Comparison of SFV with RD Rider

Advantages of SFV over RD	Disadvantages of SFV over RD
More compatible with sound economic (e.g., marginal cost) principles	Adverse effect on low usage customers, many of whom may be low income
Increased competitiveness of the utility for high usage customers from lower volumetric charge	Reduced incentives for customer-initiated energy efficiency from a lower volumetric charge
Elimination of intra-class subsidies favoring low usage customers	Possible significant increase in summer gas bills
Simpler to implement and for customers to understand	Likely stronger opposition from the public, stakeholders, and commission staff
Common pricing method for capital-intensive services	
No periodic true-up or price changes between rate cases, with longer regulatory lag	
More stable gas bills during the winter months	
Evenly allocates the recovery of fixed costs across seasons	
Neutral utility incentives for promoting or reducing gas consumption	

One way to look at a SFV rate design, relative to standard ratemaking, is that those customers who consume below the average-use level would have higher bills. The perception held by many state commissions and stakeholders is that many of the low usage customers are also low-income households.[39] One can conclude from the general rejection of SFV rate design is that even though SFV compared with a RD rider would be more economically efficient, result in more stable and levelized gas bills across seasons, would not require periodic true-ups, and is simpler for customers to understand, state commissions find either its disadvantages more persuasive or do not understand its advantages.[40] State commissions apparently attach a high significance to continuing with a rate design favorable to low usage customers and to gain public acceptability. No other explanation comes to mind, although recently opponents of SFV have argued that this rate design discourages price-driven energy conservation. The reason for less price-driven energy conservation is the lowering of the price of gas consumption at the margin to include only the gas-cost component.

IV. Strategies for assessing ratemaking practices

Ratemaking requires consideration of statutes and legal rules, economic principles, precedent, the trade-offs among different regulatory objectives, including public acceptability. Regulators need to apply their judgment on (1) what objectives ratemaking should achieve, (2) the relative significance of each objective, and (3) the willingness to impede certain objectives to advance others (e.g., the loss of economic efficiency from rates deemed fairer).

Before applying this judgment, the regulator should begin by reviewing unbiased information and analyzing how each ratemaking option advances some objectives while hindering others.[41] (See Table 2, for examples.) Overall, good

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[39] Some analysts question this perception, as a higher percentage of low-income households reside in energy-inefficient homes than other households do, because of their financial constraints in purchasing energy-conservation hardware and services. Let us assume, however, that the evidence shows low-income households to consume, on average, smaller amounts of gas than other customers do. A commission can modify the SFV rate design to charge a lower monthly fixed charge to identified low-income households. Alternatively, the utility could offer a rebate to those customers. A rebate would change the form of the subsidy, not the fact of its existence.

[40] We also observe a number of industries with largely fixed costs pricing their services on a fixed basis. These services include DSL, Internet access, local phone, and cable and satellite TV.

[41] This information could come from commission staff testimony and other advisory documents that staff can draft for commissioners.

ratemaking requires judgment, and unbiased analysis and information to arrive at a decision that best serves the public interest. Judgment reflects the preference of a decision-maker for different objectives underlying ratemaking and the strategy it applies based on the available, though often incomplete, information. This section of the paper will discuss different strategies for organizing and interpreting the information presented to commissioners.

A. Problems with the current decision process for ratemaking

An optimal process for decision-making by state commissions involves ordering and interpreting the information presented to them in a way that best advances the public interest. This approach requires that commissions: (1) define the public interest in terms of the objectives they assign to ratemaking, (2) comprehend the effect of each ratemaking proposal on advancing and impeding the different objectives, and (3) apply a logical decision-making strategy to select or reject a ratemaking proposal.

The current process applied by state commissioners for deciding on ratemaking proposals tends to have several suboptimal features in common.[42] First, commissions often do not explicitly consider and define the criteria for assessing ratemaking options. Although commissioners take into account different objectives for ratemaking, they often do not express what those objectives are, how to measure them, and what effect they have on the public interest. Commissioners might express the need for "just and reasonable" rates but they do not typically say what criteria (e.g., the acceptable degree of price discrimination, the proper allocation of business risk between shareholders and consumers) would support such rates. "Just and reasonable" thus becomes a mantra, or a post-hoc justification, rather than a decision criterion whose effect on a decision can be traced.

Second, commissioners often choose ratemaking options based on implicit weights for individual objectives, without identifying those weights in the written opinions. These opinions oftentimes fail to articulate that they favor one ratemaking practice over another because certain objectives are more important than others in serving the public interest. The public thus remains uninformed about the real reasons for the decision.

Third, ratemaking decisions often forego comprehensive "grounds up" analysis in favor of focus on the marginal gains over the status quo or over other

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[42] Suboptimal decision-making results in an outcome that fails to maximize the public interest. Such an outcome can come from inadequate availability of objective information, the intent by the decision-maker to serve his own interests or special interests, and the lack of an analytical framework from which the decision-maker processes the information presented to them.

alternatives. Commissions typically make ratemaking decisions by reacting to the positions of stakeholders, who present conflicting information, in the absence of pre-existing commission statements enunciating ratemaking principles and weights assigned to different objectives. Taking a reactive stance makes commissioners vulnerable to the political influence of individual special interests by attempting to "balance" the positions of those interests (which may have varying degrees of effective representation in the rate case) in reaching a compromised decision. Often, trying to balance those positions does not advance the public interest.

Fourth, commissioners often make trade-offs among different objectives on an ad hoc basis. They do not explicitly analyze, for example, the trade-off between allowing a utility to recover certain costs through a rider and the incentive of the utility to control those costs. Another example is the trade-off between avoiding a dramatic change in rate design and the consequences of continuing with economically inefficient rates. Over time, policy becomes unpredictable, thus diminishing credibility.

Overall, the ratemaking process across the states frequently lacks clear regulatory guiding principles, priorities or guidelines creating a moving target for commissions, utilities and other stakeholders. Consequently, the regulatory process is less efficient and resource-draining than it could otherwise be.

B. Multi-criteria decision analysis

1. Conceptual issues

An approach generically known as multi-criteria decision analysis (MCDA) is well suited for ranking and comparing different ratemaking options based on evaluation criteria. This approach can help to align unbiased and analytical information with commissioners' judgment in a systematic manner, thus allowing for more rational, transparent and efficient decision-making.[43]

MCDA is especially useful for addressing problems of a multi-objective nature, where decision-makers have to make trade-offs among multiple objectives. MCDA can assist commissions in making these trade-offs by providing them with an orderly framework to assess the implications of different value judgments for decisions. By varying the weights or significance attached to utility-initiated energy efficiency activities, for example, a commission can

[43] As one analyst has stated, MCDA can "provide help and guidance to the decision-maker in discovering his or her most desired solution to the problem (in the sense of that course of action which best achieves the decision-maker's long-term goals." See T.J. Stewart, "A Critical Survey on the Status of Multiple Criteria Decision Making Theory and Practice," *OMEGA*, vol. 2, nos. 5-6 (1992): 569-86.

determine any change in the ranking of a revenue-decoupling rider relative to other ratemaking options. Another example is where MCDA can help to determine if an increased emphasis on price-induced energy conservation causes declining-block rates to fall below some threshold level for acceptance.

The application of MCDA to ratemaking requires several steps:

a. *Frame the decision problem:* Two key questions recently have confronted state commissions: (a) Does the traditional ratemaking method deny a gas utility the reasonable opportunity to earn its authorized rate of return? and (b) Does the traditional ratemaking method provide a gas utility with a weak incentive or disincentive to support energy efficiency? A related question is how a commission can promote the twin objectives of revenue sufficiency and energy efficiency with minimal negative effects on other objectives (e.g., the "fair" allocation of business risk, public acceptability).

b. *Define the objectives and the set of evaluation criteria:* MCDA uses criteria to operationalize the objectives for comparing and evaluating potential options. An objective indicates a direction toward improved outcomes; for example, a stronger incentive for a utility to promote energy efficiency, or a better opportunity for a utility to earn its authorized rate of return. A criterion or attribute measures an objective in a way useful for analysis; the expected number of customer complaints, for example, can indicate public acceptability, and the relationship of price to marginal cost can help to gauge the presence of efficient consumption.

c. *Specify the options:* What ratemaking practices should a commission review, for example, in addressing the problem of revenue sufficiency and other problems warranting further consideration?

d. *Develop a performance matrix:* Each row in the matrix describes an option and each column measures the performance of the option against each objective or criteria (the column entries represent, for example, how well each option promotes the objective of economic efficiency). The next subsection illustrates a performance matrix.

e. *Identify the preferences of decision makers:* This step comprises the normative aspect of MCDA, where the decision-maker designates preferences for the different objectives or criteria. The identification and measurement of preferences allows the decision-maker to assign weights. A decision-maker can express her preferences by ranking the criteria, by assigning numerical weights, by identifying criteria as "must haves" and others as "desirable but optional," or by verbal evaluations.

f. *Select a method that aggregates the information presented to decision-makers for ranking and comparing the different options:* This step allows for the comparison of two or more options with varying performance over the range of objectives or criteria. The method constitutes a decision rule or strategy for sorting and evaluating the information available to decision-makers.

g. *Interpret the results and apply sensitivity or robustness analyses:* Decision-makers should not solely rely on MCDA to reach decisions; this tool, however, should assist in providing support for any decision made. The robustness of a decision also depends on whether the selected option continues to rank the highest, for example, as the decision-maker assigns a set of different weights for the objectives or criteria.

2. Illustration of MCDA application

The relevant question facing several state commissions today is what gas ratemaking options best address the factors affecting the cost and risk of providing gas service. Previously, this paper identified the underlying arguments for a different ratemaking approach. First, under the traditional two-part tariff, a utility is more unlikely in the current market environment to earn its authorized rate of return than in the past when demand for gas was more robust and stable. This outcome results from the combination of the conditions that (1) a utility recovers most of its fixed costs in the volumetric charge, (2) declining gas usage per customer is likely to continue in the future, and (3) the base rates set in the last rate case assumes no future decline in gas usage per customer. Second, since the promotion of energy efficiency has emerged as a legitimate activity of gas utilities, the extant ratemaking approach conflicts with the efforts of utilities to reduce their sales.

Let us assume that a hypothetical commission has four ratemaking objectives:[44] (1) revenue sufficiency, (2) promotion of utility-initiated energy efficiency measures that reduce gas consumption, (3) economic efficiency and (4) public acceptability. The criteria or metrics used to measure these four objectives include the likelihood that a utility would earn its authorized rate of return, the effect of energy-efficiency activities on a utility's earnings, the relationship of price to marginal cost, and the number and intensity of consumer complaints.

Let us next assume for simplicity that the three ratemaking options under consideration include the existing method (i.e., the standard two-part tariff where the volumetric charge includes most of a utility's fixed costs), a RD rider and a straight fixed-variable rate design. Although other ratemaking methods might address the alleged problems of revenue insufficiency and utility disincentives for energy efficiency – a declining block rate structure and an earnings sharing

[44] A state commission might have other objectives, but for this example it considers the four specified ones as the critical ones for decision-making.

mechanism, for example – the assumption is that the commission, for whatever reason, would not seriously consider them.[45]

The next step in the MCDA process would require the commission staff or some other objective party[46] to assess the performance of the candidate ratemaking options according to each criterion. This part of MCDA demands objective analysis and information compiled by commission staff. Judgment is necessary, but it is objective judgment. This aspect of the ratemaking process is more scientific in nature, as predicting the outcomes for the different ratemaking options relies on economic theory and empirical evidence on the experiences of the options in real-world applications. Let us assume that the analyst gives the following scores (from a scale of 1-5, with a higher score indicating better performance) to each option for each criterion:

Ratemaking Method/Objective	**Revenue sufficiency**	**Incentives for energy efficiency**	**Economic efficiency**	**Public acceptability**
Standard tariff	2	1	3	5
RD rider	5	3	3	3
SFV	5	3	5	1

For each criterion, the performance scores require at the minimum how each option compares with the others. We know that the utility is less likely under both the RD rider and SFV, for example, to experience a revenue shortfall than under the standard two-part tariff. For some readers, to say that each of these methods should receive a score of five while the standard method receives a score of two would seem hard to fathom. Yet, these scores could come from objective information and analysis. The commission staff, for example, could compute the average deviation of actual earnings from allowed earnings over the past several years, assuming each ratemaking mechanism was in place. Assigning scores to each option requires judgment by the analyst supported by objective information.[47]

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[45] The commission might eliminate outright these other ratemaking options because they impede critical regulatory objectives previously enunciated by the commission.

[46] An objective party would advocate the public interest rather than special interests.

[47] Even for the criterion "public acceptability," a commission could receive information from a survey of consumers or other focus groups to quantify the performance scores for each ratemaking option.

Next, the commissioners collectively (i.e., the decision-maker) must express their relative preference for each criterion by assigning relative weights to them. This activity is a commissioner-level activity because it requires balancing various elements of the public interest. Let us assume that commissioners assign the following weights (which add up to 100 percent):

- Revenue sufficiency: 30%
- Incentives for utility-initiated energy efficiency: 20%
- Economic efficiency: 10%
- Public acceptability: 40%

The weighting of each criterion by decision-makers (i.e., the commissioners) requires purely subjective judgment. The above illustration shows that the commissioners assign the most weight to how the public will react to any ratemaking method – a weight four times as heavy as the weight assigned to economic efficiency.[48] The hypothetical commissioners allot the next highest weight to revenue sufficiency. At the other extreme, they assign the lowest weight to economic efficiency. The commissioners consider revenue sufficiency to be three times more important in serving the public interest than economic efficiency, and one and a half times more important than incentives for utility-initiated energy efficiency.

The next step involves combining the performance scores and "criterion" weights to compare and rank the different options. One strategy or decision rule (the next subsection identifies other strategies) is to add up the scores for each option, weighted by the significance attached to each criterion, and rank the options based on the weighted scores. We can express this so-called additive linear (i.e., decision) rule as:

$$V_j = \sum w_i s_{ij},$$

where w_i represents the weight assigned to the ith criterion and s_{ij} is the score ascribed to the jth option for the ith weight. The overall value for each option (V_j) equals the performance score for each criterion (for example, the performance score of SFV for promoting economic efficiency, which in the illustration equals five, times the weight of that criterion), summed across all criteria. In other words, the overall score for each option is a weighted average performance metric, where the weights represent the relative importance of each criterion. The additive linear rule is appropriate only if the scores assigned to one criterion do not affect the scores assigned to other criteria (e.g., the performance score

[48] Commissions should not view public acceptability as something necessarily outside the control of the ratemaking process. How the public reacts to a particular ratemaking option would depend, for example, on efforts to educate customers on the justification for the option and on its content.

assigned to revenue sufficiency is independent of the score assigned to economic efficiency); that is, the criteria are mutually exclusive.

This aggregation rule involves simple arithmetic and has intuitive appeal as an indicator of the public interest. The total-score concept coincides with the utilitarian theory that options with the highest scores would have the most beneficial effect on the public interest. The additive linear rule provides a cardinal ranking of options, revealing both the order and the "outcome" distances between options. The weights reflect the trade-offs between different objectives. By pursuing the SFV option, for example, a commission impedes the "public acceptability" objective. Comparing and ranking the options based on total scores account for the importance of all criteria collectively. Under the rule, maximizing the weighted sum of the criteria leads to a desirable option.

Table 4 illustrates the construction of a performance matrix applying the weights and performance scores given above. The example shows that the RD rider has the highest total score with SFV rate design having the lowest score. The reason for the attractiveness of the RD rider, relative to the standard tariff option, is its better performance in advancing the objectives of revenue sufficiency and incentives for utility-initiated energy efficiency. The trade-off is that the commissioners deem the RD rider to have lower public acceptability. If commissioners choose the RD-rider option, implicitly they are willing to risk the possibility of public disapproval – and perhaps have planned to take measures to address the disapproval by explaining the long-term benefits of its decision -- to advance what they consider objectives that are more important.

Table 4: An Example of a Performance Matrix for Ratemaking Options

Ratemaking Option/Criterion	Revenue sufficiency w = 30%	Incentives for utility-initiated energy efficiency w = 20%	Economic efficiency w = 10%	Public acceptability w = 40%	Total score
Standard tariff	2 .6	1 .2	3 .3	5 2	3.1
RD rider	5 1.5	3 .6	3 .3	3 1.2	3.6
SFV	5 1.5	3 .6	5 .5	1 .4	3.0

Regarding the SFV option, in this example it ranks the lowest because of the combination of the high weight assigned to public acceptability and its low performance for this criterion. From the standpoint of economic efficiency, the SFV option outperforms the other options. Yet, this outcome contributes little to its total score because of the low weight assigned by the hypothetical commissioners to economic efficiency.[49] The preference of RD riders over SFV suggests that, with these two options neutralizing each other for the objectives of revenue sufficiency and incentives for utility-initiated energy efficiency, public acceptability dominates the economic-efficiency criterion. For convenience, our illustration simplifies the real world, where state commissions may frown upon SFV for other reasons. These reasons may include the adverse effect it would have on low usage customers and the fundamental change in rate design that it represents.[50]

In determining the robustness of the relative scores for the different ratemaking options, commissioners can vary the weights assigned to the criteria in addition to the performance scores for each option-criterion combination.[51] Let us first assume that commissioners view SFV as having the same public acceptability as the RD-rider option. In that scenario, SFV would have the highest score. (In Table 4, assigning a performance score of three to the SFV-public acceptability cell brings the total score for SFV to 3.8.) Assigning a higher weight to economic efficiency could also improve the score for SFV relative to the other options.

The previous illustration applying MCDA simplifies the complexities of real-world ratemaking decisions by state commissions. It shows, however, how this decision-making tool provides a conceptual framework for better understanding why commissions prefer some ratemaking options over others. If a commission seems to lean toward a particular option scoring poorly in all categories other than public acceptability, the commission would know that public acceptability implicitly dominates all others. The commission might then want to reevaluate this propensity, recognizing that it would jeopardize other objectives also deemed important (although lesser so).

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[49] This explanation seems consistent with recent experiences where RD riders have met with more approval by state commissions than SFV has. At the time of this writing, state commissions across the country have approved a SFV rate design for five gas utilities and have approved a RD rider for seventeen utilities. Gas utilities in eleven states had RD riders pending before state commissions.

[50] In other words, a commission may disfavor SFV because it violates a "fairness" standard and the "gradualism" objective.

[51] The performance scores might not require sensitivity testing when based on objective analysis. Because of the uncertainties over some of the performance score, however, commissioners may find sensitivity testing useful.

For commissions, applying a systematic approach like MCDA can help make ratemaking decisions, and the underlying reasoning, more explicit, rational, efficient and transparent. It can assist commissions in making trade-offs among multiple objectives by allowing commissions to consider the implication of different value judgments on the relative importance of each objective (i.e., whether changing the weights for the objectives will change the ranking of options). Solving a multi-criteria problem, such as ratemaking, usually involves finding a solution by making trade-offs among the different objectives. Also from a utility perspective, knowing the trade-offs, values and rationale of a commission in using MCDA could help a utility to better understand and respond to commission policy from the outset. MCDA can achieve maximum success and benefit, therefore, than if the decision-making process is done in a vacuum.

Table 5 illustrates the major tasks for commissions in executing MCDA. These tasks coincide with the seven steps of MCDA identified earlier in this section. A commission might find it difficult to perform all of these tasks quantitatively. At the minimum, however, it can at least qualitatively undertake these tasks in its decision-making process. A commission can assess whether a particular rate design would hinder certain objectives while advancing others without knowing exactly the overall effect on the public interest.

Table 5: A Generic Multi-Criteria Approach for Evaluating Ratemaking Options

Step	Task
Framing the decision problem	• What is the nature and consequences of problems with the existing ratemaking mechanism? • How would the situation look under ideal conditions? • How would alternative ratemaking options address the problems? • In general terms, what effect would the ratemaking options have on individual regulatory objectives?
Defining the objectives and evaluation criteria	• Articulating ratemaking principles underlying "just and reasonable" prices • Identifying criteria of ratemaking consistent with those principles
Specifying the ratemaking options	• Identifying ratemaking options that can address current problems
Developing the performance matrix	• Collecting unbiased information • Analyzing each candidate ratemaking option for each specified criterion • Ranking or measuring the performance of each ratemaking option for each criterion
Identifying the preferences of the commissioners	• Ranking or weighting of criteria by commissioners
Selecting a strategy or decision rule	• Combining the information from the performance matrix with the commissioner's preferences for each criterion • Comparing each ratemaking option based on a decision rule (e.g., additive linear rule)
Interpreting the results and applying sensitivity analysis	• Evaluating each ratemaking option based on the decision rule • Identifying the stability of the relative rankings with varying criterion weights and performance assessments

3. Alternative strategies or decision rules

In using the generic MCDA approach, commissions can choose from several strategies in deciding on what ratemaking practice(s) to approve and reject. The previous discussion focused on one strategy, the additive linear rule, which considers all criteria, weights them and multiplies them by the performance scores for each option. The decision-maker then ranks the options based on total scores.

The MCDA literature identifies several other strategies, which require less information and are less demanding than the additive linear rule:

a. *Bounded rationality strategy*: The decision-maker finds an option acceptable even if not optimal; this strategy avoids having to assign quantitative weights to each criterion. The decision-maker uses the rule of thumb that an option is acceptable, at least for further consideration, when it meets or surpasses a threshold for the most important criteria. Assume that commissioners deemed equity and revenue sufficiency as the only critical criteria. As long as an option seems not to violate fairness standards[52] in addition to allowing the utility a reasonable opportunity to earn its authorized rate of return, commissioners can find the option acceptable if not the superior choice. Passing muster, for example, may mean that a ratemaking option achieves a minimum score (say 3 or 4) for the criteria equity and revenue sufficiency.

b. *Elimination-by-aspects strategy*: This strategy is similar to the bounded rationality strategy in eliminating those options that fail to satisfy critical criteria or do not have highly desirable attributes. It proceeds to set a threshold value for the most important criterion and then proceed to the next important criterion, and so forth. A commission could exclude, for example, any option that received a score of two or lower on "economic efficiency." One outcome of this strategy, as well as of the bounded rationality strategy, is that an option could outperform another option for most of the criteria but the decision-maker rejects it if it fails the most significant ones. This strategy becomes less problematic to the extent that the most important criteria overwhelm the other criteria (for which this strategy gives little consideration) in advancing the public interest. The commission might assign extremely low weights to these other criteria, thus assuming that they have little effect on the public interest.

c. *Incrementalism strategy*: This strategy compares the performance of new possible options with the option currently in place. The intent is to look for options that can best overcome the problems associated with the current option. The term "incrementalism" refers to the nature of this strategy to improve

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[52] Undue discriminatory rates, and rates that shift all risks to consumers when the utility can better shoulder those risks and have some control over them, would seem to violate a fairness standard.

upon the status quo, rather than take a comprehensive review of all options in terms of their overall effect on the public interest. This strategy might limit a commission's review of ratemaking options, for example, to those that accommodate a utility facing competition and avoid the possibility of uneconomic bypass. The commission might confine its review to ratemaking options like special contracts, discounted tariffs or value of service prices. The commission might focus almost exclusively on the efficacy of a rate to allow the utility to compete on an equal basis with competitors. By ignoring other rate objectives, or giving them inadequate consideration, the commission risks approving a rate that, while promoting the objective at the center of attention, impedes other objectives that affect the public interest as well.

d. *Lexicographic strategy*: This strategy assigns a distinctly higher weight to certain criteria. It proceeds by ranking the options based on the most important criteria. If two options tie, the decision-maker then ranks them based on the second most important criterion, and so forth. If commissioners deem revenue sufficiency as the most important criterion, as an example, it could view the RD rider and SFV rate design options as equals. If commissioners identify incentives for utility-initiated energy efficiency as the second most important criterion, they may again consider the two options as equals. If then commissioners deem public acceptability as the third most important criterion, they might then decide to choose the RD rider over SFV.

e. *Conjunctive strategy*: This strategy requires that for any single option to warrant non-rejection it must meet a minimum threshold for each criterion. A decision-maker might reject outright a declining-block rate structure just because it violates the objective of encouraging price-driven energy efficiency. A seasonal rate structure might also not pass muster because of the large effect it could have on increasing utility bills during the period of peak usage.[53]

A commission can combine different strategies for selecting a ratemaking option. It can eliminate certain options, for example, using the bounded rationality strategy and then apply the additive linear rule to assess the surviving options. Taking our previous illustration, a commission might immediately eliminate the SFV option because of its low score for public acceptability, and

[53] Similar reasoning can explain the little use of real-time pricing for small electricity customers. Depending on the specific design, such pricing can result in highly volatile prices that a commission may deem would lead to widespread public opposition. Real-time pricing could also lead to customers having higher utility bills if they do not curtail their consumption during peak periods, again depending on the rate design. (See K. Costello, "An Observation on Real-Time Pricing: Why Practice Lags Theory," *The Electricity Journal*, vol. 17, no.1 (January-February 2004): 21-25.)

stabilize both a utility's earnings and customers' winter gas bills (e.g., with an extremely cold winter, rates would be adjusted downward to account for higher than normal-weather sales). On the downside, concerns may arise over the shifting of sales risk to customers and the public perception that the mechanism primarily serves to protect the utility from weather-related events, namely, warmer-than-normal winters.

Inverted-block rate: The customer pays an increased rate for gas consumed at successively higher blocks. As an illustration, the customer would pay $3.00 per thousand cubic feet (Mcf) for the 100 Mcf, and $5.00 for all consumption over 100 Mcf. This rate structure promotes energy conservation by discouraging customers from using larger quantities of gas. One form of this rate structure, referred to as a lifelines rate, has the purpose of keeping gas costs down for low-income customers, who presumably consume less gas than other customers. When the marginal cost of a utility does not increase with additional consumption, inverted rates reduce economic efficiency and result in price discrimination against high usage customers. Inverted rates may set the rate of the initial block below average cost (to provide lower prices for "essential" gas use and to better meet the needs of low-income customers), with the rate of the tail block above average cost to encourage conservation. Finally, a utility is at risk for not recovering its fixed costs through the tail blocks, which depends upon gas usage that is sensitive to weather and energy-conservation efforts.

Declining-block rate: The customer pays a lower rate for gas consumed at successively higher blocks. As an illustration, the customer would pay $5.50 per Mcf for the first 100 Mcf, and $4.50 for all consumption over 100 Mcf. This rate structure promotes the sale of gas by lowering the marginal price to larger customers from additional consumption. A utility's earnings become more stable when the recovery of fixed costs occurs in the low usage blocks, where customers will inevitably consume at the minimum. This rate structure promotes economic efficiency when the price at higher usage blocks, within which customers use gas, corresponds to variable or marginal cost. When marginal cost does not decline with higher levels of consumption, this rate structure is discriminatory in favoring larger users. Finally, by encouraging sales, this rate structure would tend to improve system utilization (i.e., the ratio of average demand to system capacity, defined over a specific time).

Cost rider: A utility adjusts its rates to recover certain costs without a formal rate review. These costs could include those that deviate from some baseline (e.g., bad-debt costs that exceed the level implicit in current rates determined by a commission in the last rate case). These costs can also include zero-based expenses. A commission might allow a utility to recover all the costs, for example, it incurred in promoting energy efficiency outside of a rate case review. One justification for a cost rider is the inadequacy of using historical cost to predict future costs. A rider has the intent of stabilizing a utility's earnings and reducing the likelihood of future rate cases. On the downside, a rider could cause a utility to have less incentive to control its cost with the diminution of regulatory lag. Another concern is that a rider would shift risks to consumers, since supposedly the utility could more easily pass through excessive costs, or any cost increase for that matter, to consumers.

Cost-based customer charge: Customer costs include those costs associated with serving customers, irrespective of the amount or rate of gas usage. These costs include operating and capital costs that vary directly with the number of customers. One issue in recent rate cases is whether a utility should raise the customer charge in line with customer costs. According to cost-of-service studies, most gas utilities have customer charges set below marginal customer costs. On grounds of economic efficiency, increasing the customer charge would improve economic efficiency, since the volumetric or usage charge would consequently better reflect a utility's variable or marginal cost. A higher customer charge would also tend to increase summer gas bills and reduce winter bills, as well as mitigate the effect of weather on customer bills. On the downside, a higher customer charge could harm low usage customers and meet with public disapproval, especially for increasing minimum summer gas bills.

Flexible rate: The utility is able to charge a price to certain customers within a specified range. A commission would designate a price ceiling and floor, within which a utility could charge. Short-run marginal cost might act as the price floor, and fully allocated cost (e.g., embedded accounting cost) as the price ceiling. This ratemaking practice is often the result of competitive market conditions compelling a utility to offer a rate to certain customers that fall below the standard or fully allocated cost rate. A flexible rate can help deter uneconomic bypass, where a customer switches to a competing fuel or gas provider when the economic cost of that provider is greater than the cost of local gas utility service. Flexible rates can result in value of service rates that account for the demand characteristics of customers. These rates are discriminatory in that the utility would charge different rates to customers in the same class (as long as they fall within the zone of allowable rates). Flexible rates raise the issue of who should bear the cost of discounts (i.e., revenue shortfalls from fully allocated cost revenues) – utility customers, utility shareholders, or both groups sharing the costs.

Special contract: The utility negotiates with a large business or industrial customer for a favorable rate and other terms and conditions. Usually the customer has service alternatives and faces unique circumstances that require a utility to offer the customer a special deal. The customer might otherwise leave the utility service area, not expand its business, or close its business. Special treatment to an individual customer constitutes a discriminatory action but one that, arguably, is justifiable under certain conditions.

Discriminatory rate in general: The utility charges two different prices for an identical service even though the costs are the same. More generally, discriminatory pricing occurs when price differences for the same service do not correspond to cost differences. Discriminatory pricing considers customers' willingness to pay, which depends on the ability of customers to find alternative suppliers or to engage in self-supply. A utility may establish a rate, for example, based on the opportunities of an industrial customer to switch to another fuel. A utility may have to offer a rate below fully allocated costs to a particular customer or group of customers to meet the demands of competitive forces. Discriminatory pricing may help a utility to reduce its surplus capacity and improve the utilization of existing capacity by offering a lower rate to customers who would respond by increasing their usage. Discriminatory pricing raises a question of fairness, especially when a favorable rate falls outside a zone of reasonableness. When a rate falls short of a utility's short-run marginal cost or lies above the price that an unregulated monopolist would charge, for example, a commission would likely find the rate impermissible.

Marginal cost rate: Favored by economists, rates that correspond to the change in total cost from a utility providing an additional unit of service (i.e., marginal cost) should give customers proper price signals. Marginal cost pricing takes a forward-looking perspective by accounting for prospective costs rather than historical costs. The rate can stimulate usage, especially when a utility has surplus capacity. Compared to the standard two-part tariff, marginal cost pricing would move the non-variable cost portion of the revenue requirement to a fixed charge. Its drawbacks include the difficulties in estimating marginal cost (e.g., long-run marginal cost) and the adjustment in rates needed to reconcile marginal-cost revenues with a utility's revenue requirement. The latter requirement might violate acceptable equity standards by charging higher rates to captive customers.

Seasonal rate: The utility charges higher rates during seasons of the year with high usage. The rationale for this price differential is that the utility incurs higher costs, both on the margin and on average, during periods of high demand. A gas utility may incur additional high-pressure distribution costs and storage costs during the winter months. The rate should result in more efficient use of gas system facilities and give customers better price signals. On the downside, a seasonal rate would cause higher winter gas bills, provoking public opposition and concerns over the aggravation of gas-service unaffordability, especially to low-income households.

Earnings sharing: The utility adjusts its rates periodically (e.g., annually) when its actual return on equity falls outside some specified band. If the band encompasses a 10-14 percent rate of return on equity, when the actual return is 9 percent, the utility could adjust its rates upward to increase its return to 10 percent. This mechanism helps to stabilize a utility's rate of return without a formal rate case review. Compared to traditional ratemaking, because of the diminution of regulatory lag this mechanism may reduce the incentive of a utility to control its costs between rate cases. On the upside, earnings sharing should reduce the frequency of future rate cases and allow adjusted rates to coincide closer to recent market developments, including those affecting a utility's costs.

Targeted subsidized rate: The utility offers a price discount to advance some social objective such as universal service and service affordability to low-income households. The rate offered to achieve these objectives might fall below short-run marginal cost, resulting in a burden on either utility shareholders or non-targeted customers, or both. A preferential rate directed at low-income households, for example, may involve a straight rate discount (e.g., a 20 percent discount from the cost-of-service rate) or a percentage-of-income payment plan (PIPP) where a utility bills an eligible customer based on a specified percentage of her household income.

EXHIBIT

Revenue Decoupling and Other Non-Volumetric Rates for Natural Gas Utilities

NARUC Staff Subcommittee on Accounting and Finance Fall Meeting

Jackson Hole, Wyoming

October 9, 2007

Cynthia J. Marple

Director, Rates and Regulatory Affairs

AGA American Gas Association

COMPANY
44

Natural Gas Costs

Commodity Costs

- 70% of Utility Revenue

Distribution Costs

- 30% of Utility Revenue

  Includes:
  - ✓ Customer Service
  - ✓ Operations
  - ✓ Maintenance
  - ✓ Depreciation
  - ✓ Taxes
  - ✓ Return on property used to provide service

American Gas Association

U.S. Natural Gas Customer Usage and Investment (Distribution Sector)

15 million new residential customers from 1980 to 2005

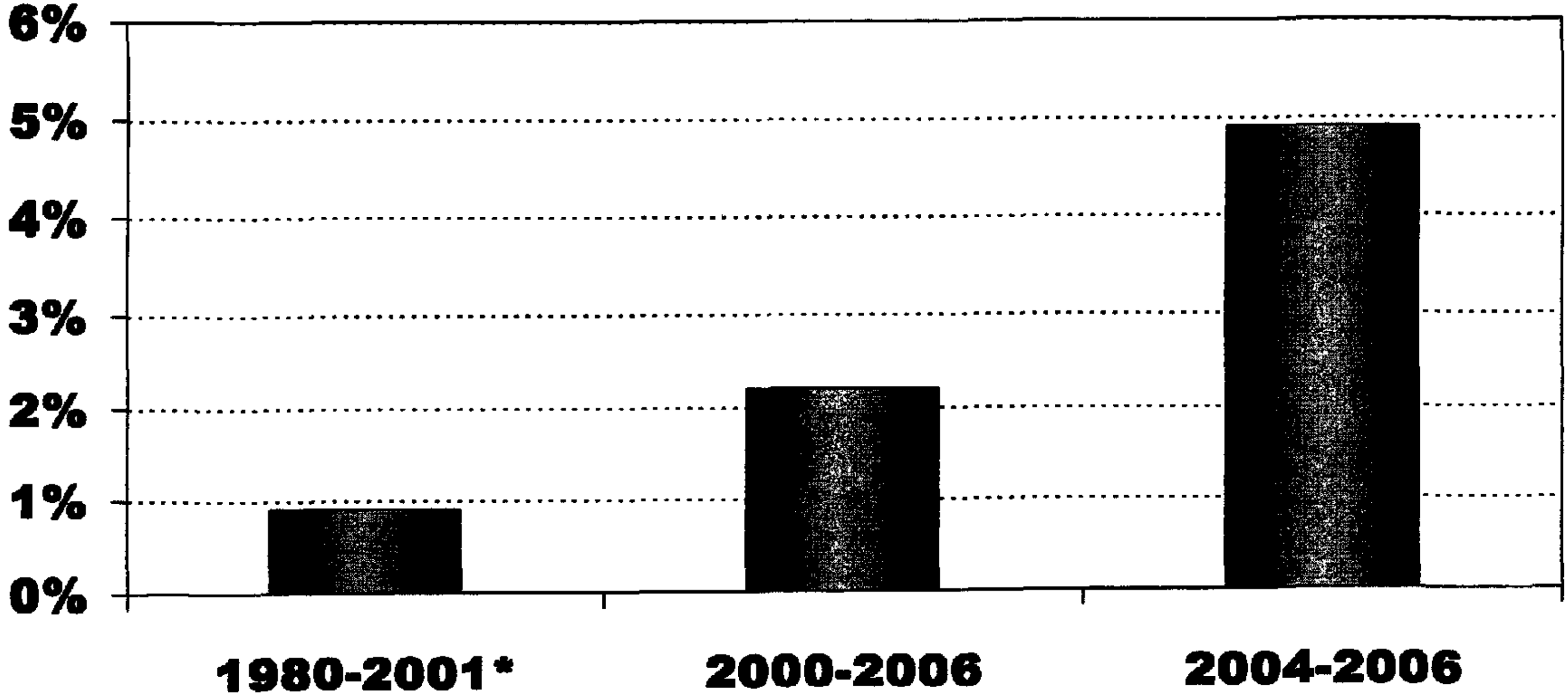
$96 billion in new construction from 1980 to 2005

1980 total residential consumption = 4.7 Tcf

2005 total residential consumption = 4.8 Tcf

American Gas Association

AVERAGE ANNUAL DECLINE IN WEATHER NORMAL GAS USE PER CUSTOMER



Total per customer consumption decreased 33 percent between 1980 and 2006

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* 2004 AGA Energy Analysis: Patterns in Residential Natural Gas Consumption, 1980-2001

Traditional Rate Design

- 19th century rate design
- Volumetric – each unit of **commodity** is assigned a pro-rata share of **distribution** costs
- Implies **distribution** revenue recovery only if customers don't conserve **commodity**
  - Increasing commodity sales is a major objective
  - Contains a financial disincentive for aggressively promoting energy efficiency and commodity conservation

Why Innovative Rate Design?

- High and volatile natural gas prices
- Global climate change
- Appliance and building efficiency
- Flat demand growth
- Under-recovery of approved costs

New Paradigm: Regulatory Goal is Shifting From Building Infrastructure to Encouraging Efficient Use of Resources

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Regulatory and Policy Changes

- 2007 U.S. House of Representatives H.R. 3221 §9511 – Passed August 4, 2007
- 2007 U.S. Senate H.R. 6 §273 – Passed June 21, 2007
- 2006 DOE/EPA/NARUC National Action Plan for Energy Efficiency
  - Utility Incentives
  - Innovative Ratemaking
- 2005 Nov NARUC Resolution on Energy Efficiency and Innovative Rate Design
  - Urged utility regulators to consider innovative natural gas rate mechanisms to increase energy conservation and reduce customers' bills.
- 2004 NRDC/AGA Policy Statement
  - PUCs should consider gas utility rate proposals and other innovative programs that remove the disincentives for encouraging conservation.
  - Endorsed by NARUC, the Alliance to Save Energy and ACEEE
- State Legislative Changes
  - New Laws: Connecticut, Minnesota, Missouri, Nevada, New York, South Carolina
  - Pending Legislation: Illinois, New Jersey, Ohio

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Types of Innovative Rates

Revenue Decoupling

Automatic Adjustments (partial decoupling)

- Weather Normalization Clause (decouples weather)

Rate Stabilization Tariffs

Flat Monthly Fee and Variants

- Fixed Monthly Distribution Charge
- Two-Tier Customer Charge
- Straight Fixed Variable (Demand Rate)
- Modified Rate Blocks

Revenue Decoupling

- A symmetrical automatic adjustment to rates that removes the variability of revenue cost recovery caused by unpredictable energy consumption due to weather or conservation
- Allows the utility to actively promote conservation and energy efficiency without having to sacrifice its financial stability
- Adjusts actual sales volumes to weather-normalized sales volumes approved in last rate case
- Retains standard bill components:
  - fixed monthly service charge
  - variable energy charge that combines a volumetric distribution charge with a volumetric commodity pass-through charge
- Adds to tariff a symmetrical tracking mechanism that "trues-up" the volumetric distribution charge

Revenue Decoupling *(Continued)*

- When sales volumes decline from level forecasted in rate case, true-up mechanism increases distribution charge
- When sales volumes increase from level forecasted in rate case, true-up mechanism decreases distribution charge
  - True-up is proportional -- cost assigned to each customer is proportional to the customer's individual usage
  - High-volume customers pay more of the true-up charge than do low-volume customers
- Prevents the utility from increasing earnings by increasing sales
  - Additional distribution charges are refunded to customers

Decoupling is NOT incentive regulation – there is no reward or bonus for the utility

American Gas Association

Decoupling Calculation

A Representative Example – Average Usage

$300,000,000 Annual Distribution Service Cost
1,000,000 Residential Customers
100 Mcf per customer per year

Per Mcf (Volumetric)

- 100,000,000 Mcf/yr - Total System Throughput
- $3 Distribution Charge/Mcf

Per Customer (Flat Fee)

- 1,000,000 Residential Customers
- $300 Distribution Charge/customer

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Decoupling Calculation *(Cont)*

Average Usage

Traditional Rate Design

5% volume reduction

- 95 Mcf/Cust/yr
- x$3 Dist. Chg/Mcf
- $285 Rev/Cust
- $15 Rev Shortfall
- $15 Loss in Yr 1
- No rate adjustment in Yr 2

Revenue Decoupling

5% volume reduction

- 95 Mcf/Cust/yr
- x$3 Dist. Chg/Mcf
- $285 Rev/Cust in Yr 1
- $15 Rev Shortfall
- 100 Mcf/Cust/Yr
- x$3.15/Dist. Chg/Mcf
- $315 Rev/Cust in Yr 2
- $15 Rev Adjustment in Yr 2

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Decoupling Calculation

High and Low Volume Usage

High Volume (133 Mcf/yr)

5% volume reduction

- $399 Expected Rev.
- 126 Mcf/Cust/Yr
- x$3 Dist Chg/Mcf
- $378 Rev/Cust in Yr 1
- $21 Rev Shortfall

- 133 Mcf/Cust/Yr
- x$3.15/Dist Chg/Mcf
- $420 Rev/Cust in Yr 2
- $21 Rev Adjustment in Yr 2

Low Volume (67 Mcf/yr)

5% volume reduction

- $201 Expected Rev.
- 64 Mcf/Cust./Yr
- x$3 Dist. Chg/Mcf
- $192 Rev/Cust. in Yr 1
- $9 Rev shortfall

- 67 Mcf/Cust./Yr
- x$3.15/Dist Chg/Mcf
- $210 Rev/Cust in Yr 2
- $9 Rev Adjustment in Yr 2

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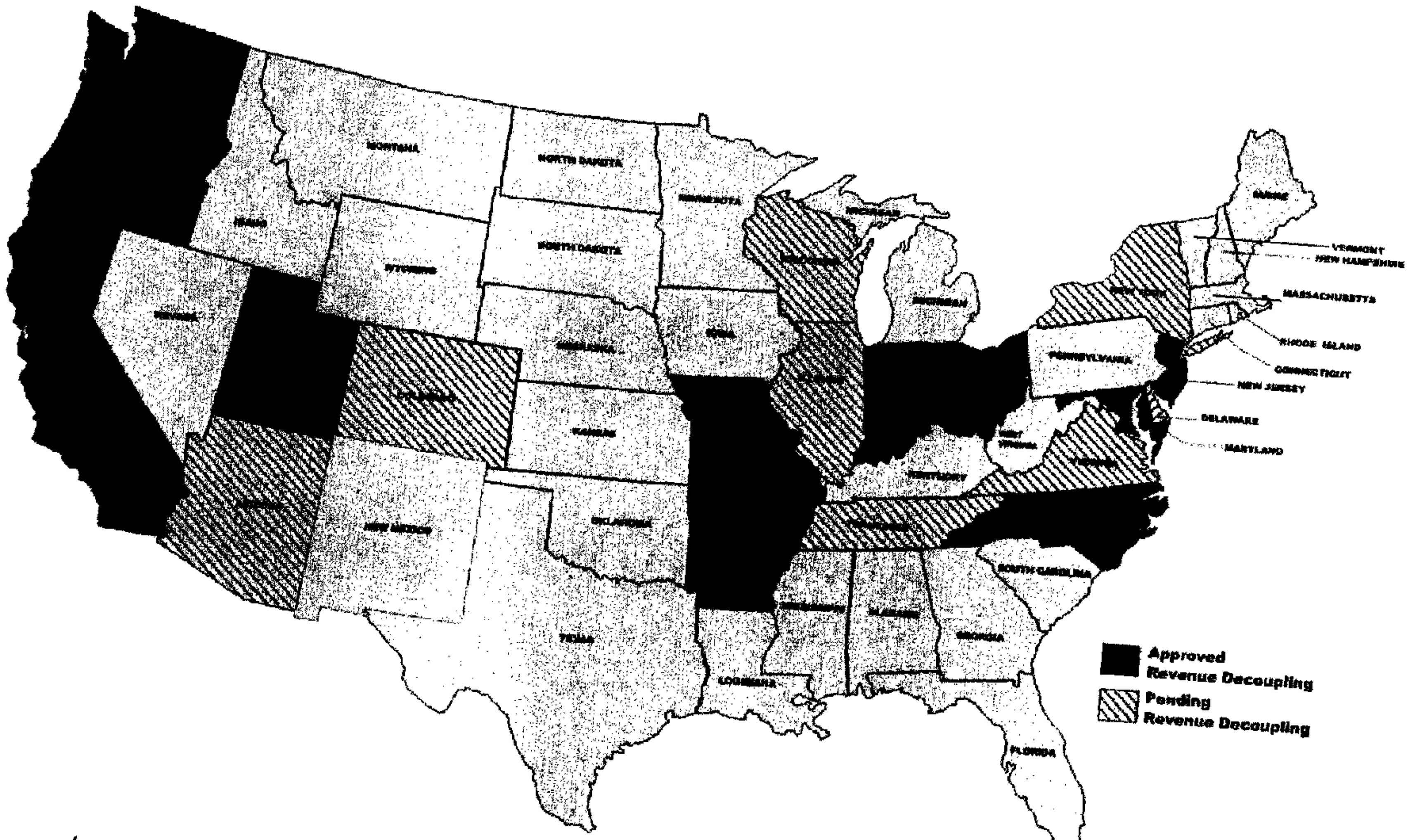
NATURAL GAS REVENUE DECOUPLING
AS OF SEPTEMBER 2007



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Decoupling Tariffs (as of September 2007)

APPROVED - 11 States

1. AR – Arkansas Western
2. CA – Pacific Gas and Electric
3. CA - San Diego Gas and Elec.
4. CA – Southern California Gas
5. CA – Southwest Gas
6. IN – Citizens Gas & Coke
7. IN – Vectren Indiana
8. MD – Baltimore Gas and Elec.
9. MD – Washington Gas
10. NJ – NJ Natural Gas
11. NJ – South Jersey Gas
12. MO – Atmos Energy
13. OH – Vectren Ohio
14. OR – Cascade Natural Gas
15. OR – NW Natural Gas
16. NC - Piedmont Natural Gas
17. UT – Questar Gas
18. WA – Avista
19. WA – Cascade Natural Gas

16 Million Residential Customers

PENDING - 8 States + DC

1. AR – Arkansas Oklahoma
2. AR – CenterPoint Energy
3. AZ – UNS Gas
4. CO – PSC of Colorado
5. DC – Washington Gas
6. DE – Chesapeake Utilities
7. IL – Integrys - Peoples Gas
8. NY – Consolidated Edison
9. NY – National Fuel Gas Dist.
10. OH – East Ohio Gas
11. OH – Duke Energy Ohio
12. TN – Chattanooga Gas
13. VA – Washington Gas
14. WI – Wisconsin Gas
15. WI – Wisconsin Electric

7 Million Residential Customers

** Of 63 Million Customers in U.S. **

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What's In Decoupling for the Customer?

- Bill stability in the only area of costs that the utility controls
- Possible reduction of commodity prices as reduced demand leads to lower prices
  - 2003 ACEEE Study projected 20% decline in gas prices from reduction in natural gas consumption of 1.9% and electric generation consumption of 2.2%
- Lower overall bills from conservation of commodity itself
- **NO** additional costs to customers beyond those approved in the rate case

NW Natural Conservation Tariff

PUC-Required Study* Found Decoupling Tariff:

- An effective means of reducing NW Natural's disincentive to promote energy efficiency
- Changed company focus from marketing to promoting energy efficiency
- Resulted in no deterioration of customer service
  - No customer complaints received regarding decoupling tariff
- Improved NW Natural's ability to recover fixed costs
- Did not shift risk to customers

Oregon now has the highest share of high-efficiency furnaces in the nation (as a percentage of new furnace sales)

* Analysis conducted by Christensen Associates (2005)

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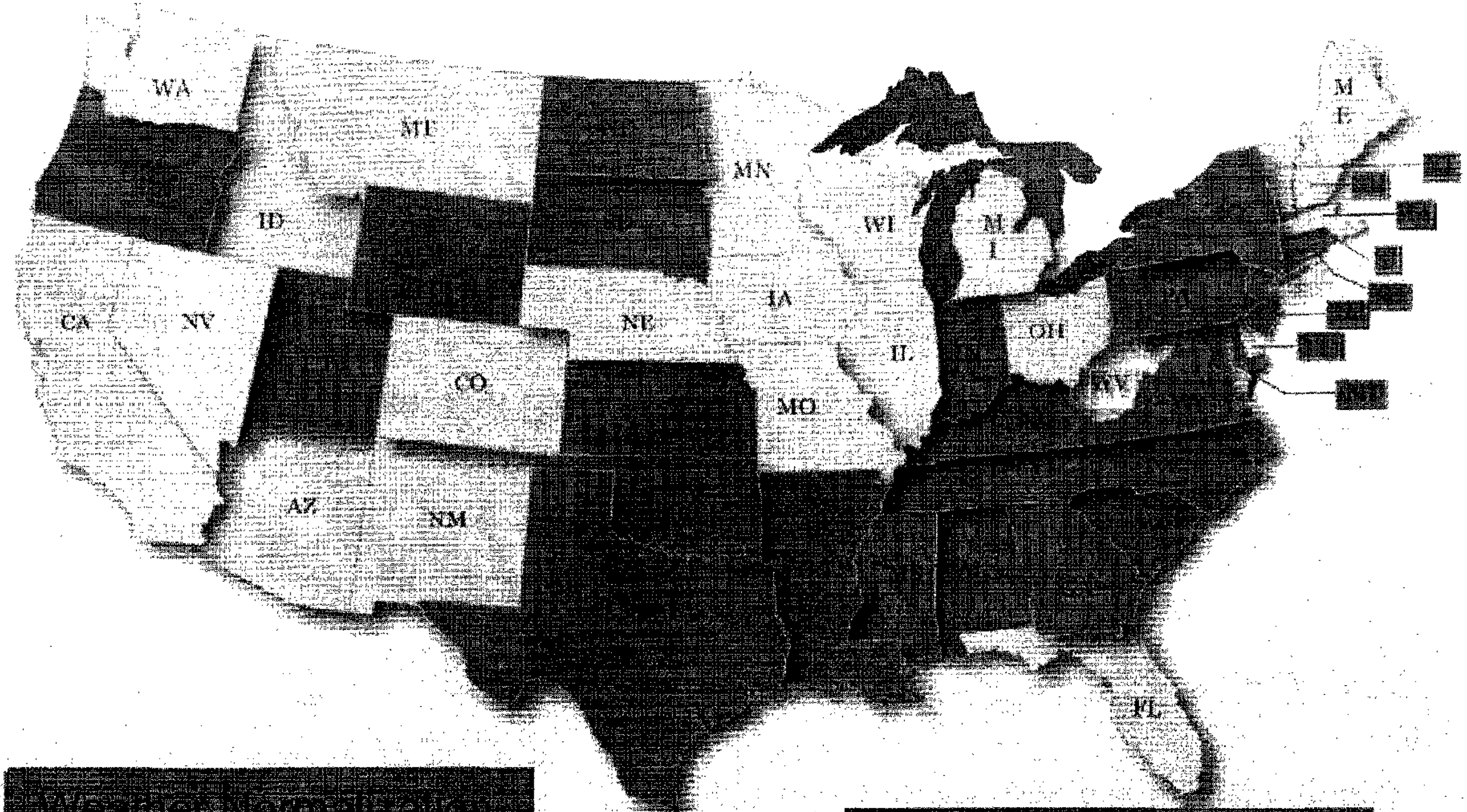
Decoupling and Conservation and Energy Efficiency Programs

- Decoupling rate design has been associated with effective energy efficiency (EE) programs
- Conservation and EE are being addressed in each proceeding
- Decisions should be based on:
  - Effectiveness of existing energy efficiency programs
  - Satisfaction with existing programs
  - Desire to push for more aggressive energy efficiency programs – this varies by state

16 of 19 current decoupling programs have a conservation program

STATES WITH WEATHER NORMALIZATION:
Partial Decoupling



Weather Normalization

16 Million Residential Customers

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Flat Monthly Fee Rate Design

Same Outcomes as Decoupling

Approved

- GA – Atlanta Gas Light – Individually determined monthly demand charge (Straight Fixed Variable)
- MO – Missouri Gas Energy - $24.69 monthly charge
- ND – Xcel Energy – Flat fee of $18.48 per month
- OK - ONEOK – Two-tier plan – Offers customers a choice
- MO – Laclede – Redesigned first rate block

Three million customers served under this rate design

Bill variability due to commodity prices is transparent to the customer

Only price signal that is meaningful

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Rate Stabilization Mechanism

- Decouples utility profits from natural gas throughput by adjusting rates to meet pre-established and authorized rate targets
- Regulatory review utilizes an expedited revenue study, as well as an expedited cost study
- NOT incentive regulation -- no reward is granted for meeting performance targets
- Expedites utility infrastructure investment between rate cases
- Symmetrical - shares efficiency savings with customers
- FERC-regulated electric transmission companies use RS

Streamlines ratemaking process and costs of utility regulation

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Rate Stabilization Tariffs

APPROVED

1. AL – Alabama Gas
2. AL – Mobile Gas
3. MS – Atmos Energy
4. MS – CenterPoint Energy
5. LA – Atmos Energy
6. LA – CenterPoint Energy
7. LA – Entergy
8. OK – CenterPoint Energy
9. SC – Piedmont Natural Gas
10. SC – South Carolina E&G
11. TX – CenterPoint Energy

PENDING

1. KY – Delta Natural Gas

3 Million Residential Customers

** Of 63 Million Customers in U.S.*

*

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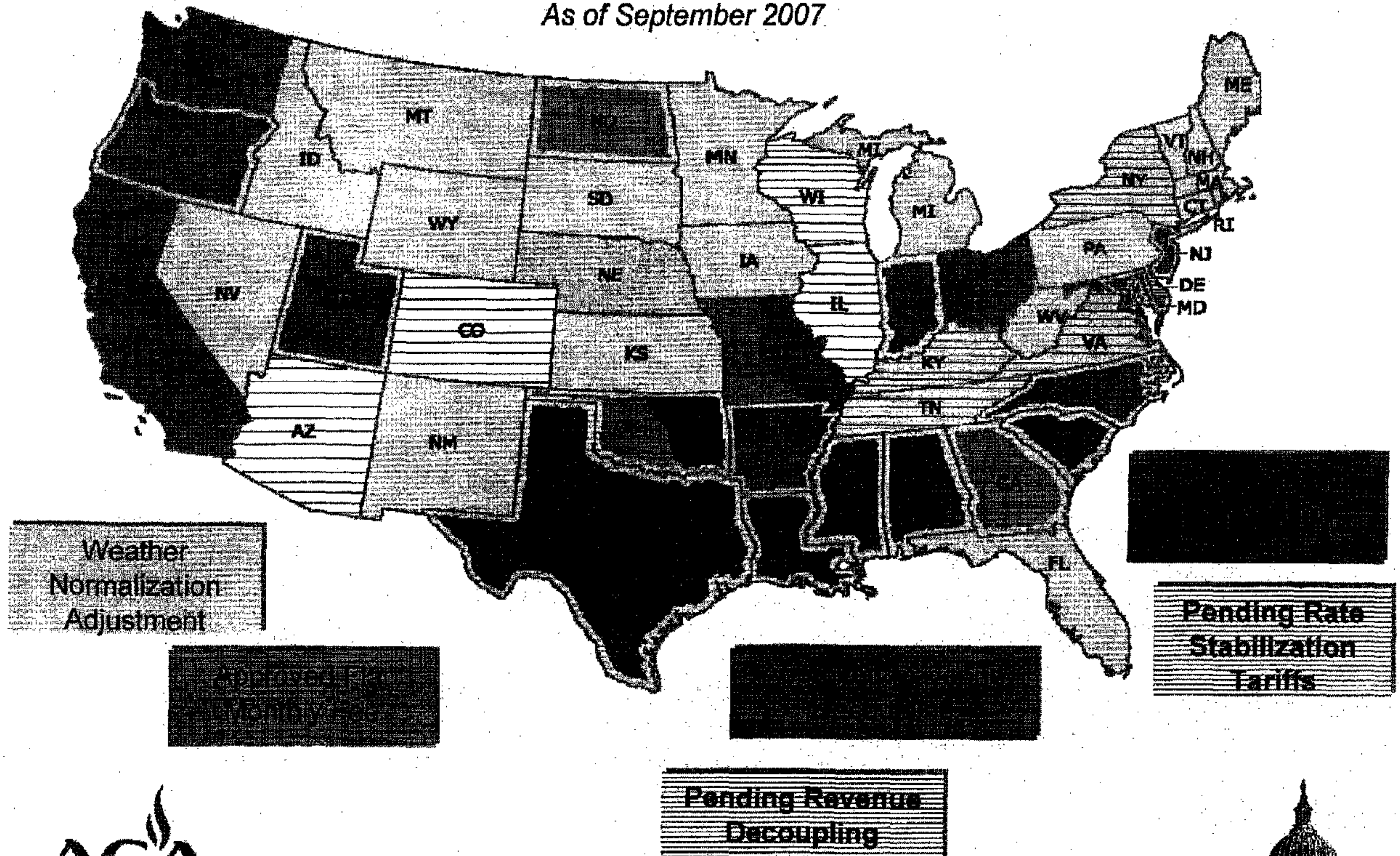
Innovative Rate Comparisons

- **Automatic Adjustment/Cost Tracker (Partial Decoupling)**
  - Rates remain volumetric but if **revenues or expenses** vary from the level in the rate case, rates are adjusted either simultaneously or in the next period. Ex: PGA, WNA
- **Revenue Decoupling**
  - Rates remain volumetric but if **marginal revenues** vary from the level in the rate case, rates are adjusted in the next period
- **Rate Stabilization Tariffs**
  - Rates remain volumetric but if **revenues and/or expenses** vary from allowed, within a band, rates are adjusted
- **Flat Monthly Fee and Variants**
  - **Fixed Monthly Distribution Charge**
    - Rates become fixed, not volumetric
  - **Two-Tier Customer Charge Option**
    - Rates become less volumetric and more fixed
  - **Demand Rates (SFV)**
    - Rates are NOT volumetric but are fixed based on the level of demand
  - **Modified Rate Blocks**
    - Rates become more fixed and less volumetric

STATES WITH NON-VOLUMETRIC RATE DESIGNS FOR NATURAL GAS UTILITIES

As of September 2007



For further information, contact

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EXHIBIT

COMPANY
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OKLAHOMA NATURAL GAS COMPANY
P. O. BOX 401, OKLAHOMA CITY, OKLAHOMA

RATE SCHEDULE 101-V
RESIDENTIAL GAS SERVICE – VOLUNTARY FIXED PRICE PROGRAM

Availability

Customers who subscribe for service under this tariff shall remain under this tariff for the entire fiscal year period in which this program is offered, beginning in November of the current year and ending in October of the following year. Additionally, customers under this tariff will utilize the Company's Temperature Adjustment Clause (TAC) and are not eligible to opt out of TAC as provided in Tariff 1141, Section 2 while enrolled in the Voluntary Fixed Price (VFP) Program. Customers are required to re-subscribe to the program each year, provided that the VFP Program continues to be offered. Customers not specifically electing to continue under the VFP Program will revert back to their applicable tariff.

Natural gas service under this rate schedule is available to any individually metered single family residential customer for domestic uses at any point on Company's system. Natural gas service under this tariff is also available to any individually metered single family residential customer for domestic uses at any point on the system of another pipeline with respect to which the Company has an agreement with such pipeline or is taking gas pursuant to a tariff for such service but only to the extent that: (1) such single family residential meter exists as of the effective date of this tariff; (2) service is required by operation of law; or (3) service is agreed to by such other pipeline.

This tariff shall also be available for individually metered two-family dwellings when the customer meets the following two (2) criteria: (1) The customer is responsible for payment of the bill; and (2) The customer is an occupant of one of the two dwellings served by the single meter. This rate shall not be available for any 3-(or more)-family dwellings served by one meter. The Company shall have the right to determine and confirm from time to time that the customer meets the criteria contained herein. Denial of access to the property to determine compliance with such criteria shall constitute grounds for denial of service pursuant to this tariff.

Gas service is not available under this rate schedule for resale to others or for standby service.

Rate Choices

OKLAHOMA NATURAL GAS COMPANY
P. O. BOX 401, OKLAHOMA CITY, OKLAHOMA

The charge for recorded consumption of gas at one point of delivery in any month is as follows:

	Service Charge	Delivery Fee
For Rate Choice A	$9.00	$1.9967 Per Dth

	Service Charge	Delivery Fee
For Rate Choice B	$20.00	$0.2367 per Dth

Customer Option Placement

Each customer's individual rate schedule will be determined based on the annual normalized volume at the customer's service location for the twelve (12)-month period ending on July, 31 2005. If the customer's service location's annual normalized volume is less than 75 Dth, then the customer's account will be placed on Option A.

If the customer's service location's annual normalized volume is 75 Dth or greater, then the customer's account will be placed on Option B.

An anticipated annual normalized usage level assessment will be conducted on each new service and for existing service as of July 31, 2005 that has less than twelve (12) months of service. The result of this assessment will decide the initial placement of the new account.

A customer may switch options at any time during the year provided that the customer agrees to remain on the alternative rate choice for a period of no less than twelve (12) months after switching options.

Each year, the Company shall undertake a customer specific billing assessment and issue a credit for all customer accounts meeting the following criteria: 1) must be on choice B, 2) must be under the TAC option, 3) must have 12 consecutive billing periods on choice B at the time of the evaluation, 4) must have usage of less than 70 Dth. The credit will equal the difference between what was billed to each account under choice B and what would have been billed under choice A for the 12 month evaluation period.

Date Issued October 7, 2005 **Date Effective** October 7, 2005

Authorized by 512287 (Order No.) PUD 200400610 (Cause No.) October 4, 2005 (Date of Letter)

Issued by [signature] (Name of Officer) Mgr. - Rates & Regulatory Rptg. (Title)

APPROVED
OCT 6 2005
DIRECTOR OF
PUBLIC UTILITIES

Note: Meter readings will be recorded in hundreds of cubic feet (.1 Mcf) or multiples thereof.

Commodity Cost of Gas

The indicated rates do not include the applicable commodity cost of gas which shall be added pursuant to Special Terms and Conditions, Tariff No. 1001-V.

Subject to:

Special Provisions	**Tariff**
Purchased Gas Adjustment Clause	1001-V
Gross Receipts & Franchise Tax Adjustments	1011
Order of Curtailment	1031
Miscellaneous Special Charges	1041
Miscellaneous Terms and Conditions	1051
Commission Assessment Fee	1075
Take or Pay Settlement Amortization Rider	1091
Temperature Adjustment Clause	1141
Line Loss Rider	1191

Payment
Bills are to be paid within 20 days after the date of Company's bill to Customer.

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EXHIBIT

COMPANY
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CHRISTENSEN
ASSOCIATES
ENERGY CONSULTING

Economic Analysis and Consulting

A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural

by

Daniel G. Hansen
Steven D. Braithwait

March 31, 2005

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Madison, Wisconsin 53705-2164

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Table of Contents

1. INTRODUCTION AND BACKGROUND

Traditional rate-of-return regulation may create incentives for energy utilities that are counter to public policy objectives. In the case of natural gas, this occurs in large part because utilities have costs that are both fixed and variable, but collect revenue to recover those costs primarily through volumetric prices (*i.e.*, retail $/therm prices applied to consumers' energy consumption). To recover their fixed costs, including their allowed return on capital, utilities typically forecast the total amount of energy they expect to sell in a given period, and set a price that will recover the appropriate amount of revenue toward fixed costs on the planned level of sales. This process tends to produce the following outcomes:

- The utility has an incentive to under-forecast sales for the rate-making period, thus increasing the retail price and improving the opportunity to recover fixed costs. The regulatory agency has a corresponding interest in over-stating sales forecasts, which would lead to lower prices. The resulting contrast in incentives typically leads to contentious rate cases.
- Variation in consumers' energy consumption due to factors such as unexpected weather conditions causes variation in both consumers' bills and the utility's net revenue (*i.e.*, revenue toward fixed-cost recovery).
- Once rates are set, the utility has a disincentive to take actions to encourage their customers to adopt energy efficient practices that may result in lower sales, as this will reduce their net revenues, and thus their ability to recover their fixed costs.

Consequently, utilities and regulatory agencies in a number of states have experimented with alternative mechanisms designed to alter some of the above incentives and outcomes. In 2002, the Oregon Public Utilities Commission (Commission) approved a Distribution Margin Normalization (DMN) mechanism for Northwest Natural Gas Company (NW Natural). As part of the Order, the Commission also approved NW Natural's proposal for Public Purposes Funding to support low-income bill payment assistance, low-income weatherization assistance, and enhanced energy efficiency programs. Finally, the Order imposed service quality standards on NW Natural, specifying penalties associated with violating specific service quality measures.

The Commission Order implementing DMN required NW Natural to submit an independent study regarding the effectiveness of the mechanism. The study will contribute to the process of determining whether to continue DMN beyond September 30, 2005. NW Natural has retained Christensen Associates Energy Consulting, LLC (CAEC) to perform this study, and has expanded the scope of the study to also include a partial evaluation of the Weather Adjusted Rate Mechanism (WARM) as well as a comparison of the combination of DMN and WARM to a full decoupling mechanism.

The report is organized as follows. Section 2 provides an overview of DMN, including a description of the calculations and its expected incentive effects. Section 3 provides a similar overview of WARM. Sections 2 and 3 focus on *theoretical* evaluations of DMN and WARM, or what we would expect to happen given the calculations contained in the mechanisms. Section 4 presents data and analysis regarding the effects of DMN, including revenue effects, changes in marketing efforts, organizational changes, financial effects, and service quality issues. Section 5 compares DMN to other rate mechanisms that may be able to achieve similar goals. Section 6 provides a summary and conclusions, including answers to the specific questions raised by the Commission in Order 02-634.

2. OVERVIEW OF DISTRIBUTION MARGIN NORMALIZATION[1]

2.1 Description of Mechanism

A primary goal of DMN is to reduce the uncertainty around NW Natural's distribution fixed cost recovery. That is, because distribution fixed costs are recovered through volumetric rates that are established based upon an expected level of sales, deviations from expected usage (caused by weather, economic conditions, price changes, random variations, etc.) will affect the amount of fixed costs recovered. In addition, by ensuring that the utility recovers its fixed costs regardless of customer usage levels, DMN reduces the utility's disincentive to promote energy efficiency. The DMN mechanism agreed to in Oregon is limited to "decoupling" revenues associated with 90% of the non-weather induced variation in usage for residential and commercial customers.

2.1.1 Elasticity Adjustment

There are two ways in which DMN affects revenues: the *elasticity adjustment* and the *deferral component*. The elasticity adjustment adjusts margin recovery for the effects that changes in retail tariff prices are expected to have on use per customer (*e.g.*, customers are expected to reduce consumption if natural gas prices increase). To understand the elasticity adjustment, consider an example in which the retail price increases over a particular time period. The elasticity adjustment mechanism first adjusts original "baseline" use per customer downward (using a price elasticity value specified in the tariff) to account for the fact that customers are expected to reduce usage when prices increase. This reduction in baseline usage is then used to calculate the increase in the dollar per therm margin required to keep the allowed fixed cost recovery constant on a per-customer basis. This new margin value is then passed through to the standard tariff, which in this example implies increasing the per therm rate. Ultimately, the change in the baseline use per customer value produced by the elasticity adjustment also affects the deferral component of DMN, which is described in detail later in this section.

The revenue effects of the elasticity adjustment alone are described in Equations 1a through 1c.[2]

Equation 1a: Elasticity Adjustment Revenues = $(M' - M) * Q^{A,M}$

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[1] This mechanism has also been referred to as the Partial Decoupling Mechanism (PDM) and the Conservation tariff.

[2] For simplicity, we represent the calculations in the first year after a rate case, so that the initial margin (M) and baseline use per customer (QPC^{B}) are determined in the rate case. In practice, each year's DMN adjustment uses the baseline use per customer and margin values from the previous year.

Equation 1b: $M' = M * QPC^{B} / QPC^{B,P} + \Sigma_i M_i * QPC^{B}_{i} / QPC^{B,P}$

Equation 1c: $QPC^{B,P} = QPC^{B} * [(P/P^{B} - 1) * \varepsilon_d + 1]$.

Where,

M = initial margin for recovery of fixed costs in the standard tariff;
M' = the adjusted margin resulting from the elasticity adjustment;
$Q^{A,M}$ = metered natural gas consumption in therms;
QPC^{B} = baseline use per customer, initially determined through a rate case;
$QPC^{B,P}$ = price elasticity adjusted baseline use per customer;
M_i = margin components approved subsequent to the most recent rate case;
QPC^{B}_{i} = baseline use per customer at the time that M_i was approved;
P = total dollar per therm tariff price for the coming year (excluding the elasticity adjustment to margin);
P^{B} = baseline total price per therm, initially determined through a combination of a rate case and the calculations resulting from the purchased gas cost adjustment; and
ε_d = the class-specific price elasticity stipulated in the Order (-0.172 for residential customers and -0.110 for commercial customers).

Equation 1a shows that the total revenue effect associated with the elasticity adjustment equals the change in margin times the total metered consumption. Equation 1b shows how the margin is affected by the elasticity adjustment. The margin is adjusted so that the product of baseline use per customer and the margin remains constant (*i.e.*, so that the total margin contribution per customer remains constant). The summation term in Equation 1b accounts for any additions to allowed margin since the rate case that established the baseline. Equation 1c shows how the baseline use per customer is adjusted for price changes. This is accomplished by determining the percentage change in price, multiplying it by the price elasticity in order to obtain the percentage change in baseline quantity, and applying this percentage change to the baseline use per customer.

2.1.2 Deferral Component

Equations 2a and 2b show the calculations contained in the deferral component, which is the part of the DMN revenue adjustments that is intended to compensate NW Natural for conservation efforts (and stabilize fixed cost recovery more generally).[3]

Equation 2a: DMN deferral amount = $90\% * [(QPC^{B,P} * C) - Q^{WN}] * M'$

Equation 2b: $Q^{WN} = Q^{A,S} + C * \beta * (HDD^{N} - HDD^{A})$.

Where,

[3] This simplified description does not consider many complicating factors that have arisen in practice, such as the modifications to the baseline quantities due to the reclassification of customers following the last rate case.

$QPC^{B,P}$ = baseline use per customer adjusted for price elasticity effects;
M' = the per therm margin, adjusted for price elasticity effects;
Q^{WN} = weather normalized sendout therms for the residential or commercial class;
$Q^{A,S}$ = actual sendout therms for the residential or commercial class;
C = the number of customers in the residential or commercial class;
β = a parameter representing the change in therms per customer per change in heating degree day (HDD), as contained in the WARM tariff;
HDD^{N} = normal heating degree days for the billing period, using a base of 59 degrees for residential customers and a base of 58 degrees for commercial customers; and
HDD^{A} = actual heating degree days for the billing period, using a base of 59 degrees for residential customers and a base of 58 degrees for commercial customers.

These calculations are made each month. The resulting surcharges or refunds accumulate in a deferral account, and are collected or refunded through rates in the following year (which begins on October 1).

The weather normalization of actual usage shown in Equation 2b is performed using methods developed in NW Natural's most recent rate case. Heating degree day (HDD) data are adjusted ("cycle-ized") to match the timing of the billing data. The normal weather measure is a district-weighted average for the 25 years ending in 2000. The weather normalization method adjusts actual usage (measured on a sendout basis) for the expected difference in usage between normal and actual weather conditions.

2.2 Expected Risk Effects

In this section, we discuss the risk properties of DMN. For this purpose, we define "risk effects" as the changes in revenue flows due to changes in the outcomes of uncertain variables. We consider four sources of uncertainty that create risk in NW Natural's fixed cost recovery and customer bills: weather, natural gas prices, economic conditions, and other random factors.

DMN does not change the risk associated with uncertainty in weather conditions, as the usage amount used to calculate deferrals is weather normalized.

Changes in natural gas prices affect the amount of natural gas that customers will use. Therefore, the risk that NW Natural faces with respect to gas price uncertainty is that when prices rise, customer usage levels decrease, reducing fixed cost recovery. At the same time, the price increase causes customers' bills to increase (as long as any reductions in usage are not offset by the increase in the gas price). Because both NW Natural and its customers are made worse off by increases in natural gas prices, the fact that DMN reduces this risk for NW Natural means that the risk is shifted to customers. However, the component of DMN that shifts this risk is the elasticity adjustment, over which there appears to be no dispute with respect to its appropriateness. That is, various parties' views regarding the efficacy of DMN seem to hinge on their opinion of the decoupling mechanism, not the elasticity adjustment.

DMN has the *theoretical* potential to shift economic risk from NW Natural to its customers. For example, in a period of declining economic conditions (*e.g.*, an increasing unemployment rate) customers may reduce usage in an attempt to reduce their bills due to income constraints. However, the DMN deferral component would increase customer bills (in the following year), thus reducing the amount of bill reduction that customers can achieve. While the possibility of this form of risk shifting exists in theory, our analysis in Section 4.3 indicates that this problem does not appear to exist in practice in NW Natural's service territory (*i.e.*, the analysis of residential and commercial use per customer indicates that they do not appear to be significantly affected by changes in economic conditions).

Controlling for weather conditions, natural gas prices, and economic conditions, some residual variation can be observed in use per customer that must be due to other uncertain factors. (The analysis in Section 4.3 indicates that the residual variation in use per customer is small relative to the variation explained by weather and natural gas prices.) For these other factors, DMN reduces risk for both NW Natural and its customers. That is, the reduction in the variability of revenues under DMN leads to more certainty (*i.e.*, less risk) for both NW Natural and its customers. However, because the customers experience a DMN rate adjustment as a change in the volumetric price in the *following* year, DMN does not reduce their *current* cash flow risk. For example, when usage exceeds baseline levels, customers' current bills reflect the over-payment of distribution costs. They are not "paid back" for the over-recovery until the following year. Therefore, while customer bill risk is reduced over long periods of time (*i.e.*, their "wealth" risk is reduced), customers may not perceive their risk reduction to be significant.[4]

In theory, DMN should be effective in reducing the variability of distribution cost recovery. By design, the effectiveness of DMN in accomplishing this task has been reduced in two ways (relative to full decoupling or fixed/variable rates). First, weather-induced variations in fixed cost recovery are eliminated from the adjustment mechanism through the weather normalization of usage. Second, only 90% of the remaining margin variability is covered by the deferral component of DMN. Therefore, NW Natural retains all weather-related variability and 10% of non-weather related variability in distribution fixed cost recovery from customers on DMN.[5]

In testimony supporting decoupling, NW Natural has asserted that the risk reduction to NW Natural caused by DMN is mirrored by a corresponding reduction in risk to its customers. For example, when NW Natural over-recovers revenue, its customers over-pay, thus providing the opportunity to reduce risk for both parties. This assertion is valid with respect to weather risk (which is addressed by full decoupling, which was the topic of NW Natural's testimony) and risk due to the other non-price and non-economic factors. The theoretical potential for DMN to shift economic risk from NW Natural to its

[4] Another reason that customers may not perceive a large reduction in their risk is that DMN covers only the distribution portion of the bill and not the energy costs. Therefore, DMN adjustments will tend to be small in proportion to the total bill regardless of when they are applied.

[5] Note that WARM addresses weather-related variations in revenue toward distribution cost recovery.

customers is not supported by empirical analysis (see Section 4.3), and the shift of natural gas price risk from NW Natural to its customers that is caused largely by the elasticity adjustment is accepted by both Commission Staff (through its support of a stand-alone elasticity adjustment) and NW Natural.

2.3 Expected Incentive Effects

DMN has the potential to produce a number of incentive effects. Four potential NW Natural incentive effects are addressed in this section, followed by a discussion of the effect of DMN on customer incentives.

2.3.1 Reduced Disincentive to Promote Conservation

Prior to the introduction of DMN, NW Natural had a strong disincentive to promote energy efficient appliances and general conservation efforts. This was due to the fact that any conservation that occurred (*i.e.*, any reductions in natural gas sales from the levels on which retail rates were based) reduced the amount of distribution cost recovery.[6] In fact, NW Natural benefited by promoting load growth because it could achieve excess distribution cost recovery whenever usage levels exceeded the levels used in setting retail rates. By reducing the link between sales and distribution revenues, DMN should be effective in reducing NW Natural's disincentive to promote conservation. However, it does not eliminate the disincentive completely, as NW Natural continues to retain 10% of any non-weather related over- or under-recovery of distribution costs.

The change in incentives with regard to conservation has a less appealing aspect. That is, NW Natural has asserted that direct use of natural gas is itself energy efficient. This is based on the idea that using electricity generated from natural gas is less efficient than using the natural gas directly in applications such as cooking, space heating, clothes drying and water heating. However, with DMN, NW Natural has a reduced incentive to promote fuel switching among current customers. For example, prior to DMN, if a customer converted to a natural gas water heater, NW Natural's revenues increased through the standard tariff. With DMN, the 90% of the increase in revenues is offset by a customer refund generated through the deferral component (though only a very small percentage of this refund will go to the customer that converted the water heater). It could be that in the absence of DMN, NW Natural's incentives to promote these conversions were too high (by causing conversion customers to pay increased fixed costs as well as natural gas energy costs), but the *change* in incentives caused by DMN could cause NW Natural to reduce its efforts to promote conversions that it has advocated as being energy efficient.

2.3.2 New Customer Connections

The DMN deferral mechanism incorporates a baseline use per customer measure that is intended to represent the average usage of the customers in the class (adjusted for responses to changing prices). Because of this, DMN gives NW Natural a short-term

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[6] Lost revenue adjustments were in place prior to DMN. These compensated NW Natural for reductions in revenues attributed to some programs, such as the residential high-efficiency furnace program. Section 5.3.2 presents a discussion of the effectiveness of lost revenue adjustments in reducing disincentives to promote energy efficiency.

incentive to provide new connections to low usage customers. Each additional customer that is smaller than average generates surcharges through the deferral mechanism that result in additions to NW Natural's net revenues.

At the time DMN was approved, NW Natural agreed that it would not modify its main extension policies in response to DMN. One way to remove this potential incentive regarding new customer connections is to apply DMN only to existing customers. This would maintain non-DMN incentives for new connections customers, who would only be included in DMN adjustments following the next rate case. However, an offsetting effect of removing new connections customers from DMN is that it might make NW Natural more resistant to altering building codes to improve energy efficiency and reduce their incentive to promote the use of high efficiency appliances in new construction. Section 4.4.3 contains a more complete discussion of new connections.

2.3.3 Uncollectible Accounts

A concern was communicated to us regarding whether DMN affects NW Natural's incentive to pursue uncollectible accounts. An examination of the calculations in Section 2.1 reveals that uncollectible revenues are unrelated to the DMN mechanism. That is, because uncollectible revenues do not flow into the DMN deferral mechanism, we conclude that DMN does not have undesirable incentive effects in this area.

2.3.4 Customer Service

Two factors lead us to believe that the DMN Order does not present negative incentive effects with respect to the provision of customer service. First, the Commission implemented service quality standards and penalties as part of the Order approving DMN. Second, although NW Natural is a monopoly provider of natural gas services in its territory, it does compete with other fuels to serve customers. This fact, combined with the fact that the DMN deferral mechanism compensates NW Natural based on the *current* number of customers in the class, leads us to conclude that DMN provides NW Natural with the same incentive to attract and retain customers. A related concern has been expressed to us that DMN may provide NW Natural with a disincentive to resolve outages in service. The thinking behind this concern is that DMN compensates NW Natural for reductions in usage that occur during outages (while under standard rates, NW Natural loses revenues until the outage is repaired). Given NW Natural's competitive concerns and the fact that natural gas outages can present a significant safety hazard, we do not believe that this effect will exist in practice. Section 4.6.2 provides additional discussion of this issue.

2.3.5 Incentives on Customer Behavior

Regarding the incentive effects of DMN on customer behavior, there is only one minor effect to consider. That is, relative to standard tariffs, DMN may slightly reduce customers' incentives to independently conserve energy (and conversely, DMN slightly decreases the cost of increasing consumption). In the absence of DMN, customers are "over-paid" for conservation efforts, as they pay less fixed distribution cost in addition to the reduction in their energy cost.[7] By ultimately reducing the amount of this over-payment by 90%, DMN reduces the aggregate incentive for customers to conserve.

However, the effect is likely to be very small in practice because the revenue effects of *individual* customer conservation efforts are spread across the *entire* customer class, and delayed until the following year. That is, in the month that the conservation activities are undertaken, the conserving customer receives the full "over-payment" of fixed distribution costs through the standard tariff rate. The shortfall in revenues that this produces is added to the tracking account (with a 10% reduction), deferred until the following year, and recovered through an increase in rates to the *entire* class. Therefore, the conserving customer only re-pays its avoided distribution costs in proportion to its share of total class usage in the following year. Because of this dilution effect, the incentives for individual customers to conserve energy is largely unaffected by the presence of DMN.

2.4 Possibilities for Gaming the Mechanism

In order to implement DMN, NW Natural and the Commission must agree to certain parameter values, including:

- Price elasticity values for residential and commercial classes;
- Definition of normal weather;
- Weather sensitivity parameter (used to weather normalize use per customer); and
- Baseline use per customer for residential and commercial classes.[8]

Each of these parameters introduces the potential for "gaming" the outcome, by which we mean that parties may have an incentive to influence the calculations in order to produce an outcome that is more favorable to customers or the utility.

This gaming issue must be considered from two perspectives: DMN as a stand-alone mechanism; and DMN in combination with WARM. That is, as we will point out, some of the ways in which DMN outcomes might be influenced are countered by an offsetting effect from WARM, thus reducing or eliminating the incentive to game the parameter value.

2.4.1 Price Elasticity Values

The primary effect of setting the price elasticity incorrectly is that it changes the amount of revenues that flow through the deferral accounts, which leads to a reduction in the extent to which distribution revenues are adjusted for price effects (because deferrals are subject to the 90% factor). Note that if the 90% factor were removed, the price elasticity value would have no effect on total revenues collected or refunded; errors in the price

[7] Environmental organizations argue that the "over-payment" does not exist because energy prices do not account for all of the costs that energy use imposes on society (in terms of environmental impacts).
[8] There is an additional gaming concern with respect to new customer connections, which is discussed in Section 2.3.2.

elasticity would simply shift dollars from the elasticity adjustment to the deferral component.[9]

However, because of the 90% factor, only small revenue effects are associated with setting the price elasticity incorrectly. Table 2-1 shows the net revenue effect associated with increasing or decreasing prices when the elasticity value is too high or too low.

Table 2-1: DMN Revenue Effects of Setting the Price Elasticity Incorrectly

	Price Increase	**Price Decrease**
ε_d too low	Surcharge too low	Refund too low
ε_d too high	Surcharge too high	Refund too high

To better understand this table, we will walk through the reasoning associated with the upper left cell ("surcharge too low"). For this example, assume that normal weather conditions occur. When the base tariff price increases, use per customer is expected to decrease. When this happens, DMN produces surcharges to customers that should make NW Natural whole for the lost margins. However, if the elasticity value is set too low (*e.g.*, suppose the true elasticity is -0.3, but it is set at -0.172 for DMN calculations), the use per customer is assumed to fall by less than it actually will. This causes the per therm margin to be set too low, reducing the revenues from the elasticity effect shown in Equation 1a. Offsetting this effect is the fact that, because baseline use per customer is too high, the deferral component will produce surcharges to customers (that would not have existed had the baseline usage been adjusted correctly). In the absence of the 90% factor applied to deferrals, the error in the deferrals would exactly offset the error in the elasticity adjustment. However, because of the 90% factor, total surcharges to customers end up being too low, resulting in lost distribution cost recovery for NW Natural.

Examining each cell of Table 2-1 leads to the following conclusions with respect to gaming the price elasticities: if prices are expected to increase, customers will benefit if the price elasticity is set too low and NW Natural will benefit if the price elasticity is set too high. Conversely, if prices are expected to decrease, customers will benefit if the price elasticity is set too high and NW Natural will benefit if the price elasticity is set too low.

The magnitude of this incentive is relatively small, and would disappear completely if the 90% factor were eliminated. The gaming effects of this parameter are unaffected by the presence of WARM.

2.4.2 Normal Weather Definition

The definition of normal weather in the form of heating degree days (HDD^N) is required for the DMN deferral calculation. To evaluate the effects of setting HDD^N incorrectly,

[9] In the absence of the 90% factor, the price elasticity value would change the *timing* of revenue recovery, but not the *level* of revenue recovery. That is, revenues recovered through the elasticity adjustment come from current bills, while revenues recovered through the deferral component come from bills in the following year.

assume that the weather sensitivity parameter (β) is set correctly and actual heating degree days (HDD^A) are at their true normal value. Setting HDD^N too low (the equivalent of assuming that winters will be too warm) leads to a consistent over-adjustment of use per customer for weather, producing surcharges to customers. Conversely, setting HDD^N too high (the equivalent of assuming that winters will be too cold) leads to a consistent under-adjustment of use per customer for weather, producing refunds to customers. Therefore, all else equal, customers benefit when normal weather is set too cold, and NW Natural benefits when normal weather is set too warm.

The incentive to influence the definition of normal weather is dramatically reduced when DMN is combined with WARM. This is discussed in more detail in Section 3.4.

2.4.3 *Weather Sensitivity Parameter (β)*

The weather sensitivity parameter determines how much use per customer is assumed to change as weather conditions (HDDs) change. Currently, the same values are used in DMN and WARM, and they were estimated as part of the load forecasting process undertaken during the UG-152 rate case.

The effect of errors in setting β depends upon whether HDD^A is above or below the assumed value of HDD^N, as shown in Table 2-2.

Table 2-2: Revenue Effects of Errors in Setting the Weather Sensitivity Parameter

	$HDD^A < HDD^N$	$HDD^A > HDD^N$
β too low	Surcharges	Refunds
β too high	Refunds	Surcharges

Consider the result when β is set lower than its true value and winter weather is warmer than normal (represented by the top left cell in Table 2-2). Warm winter weather reduces actual use per customer below baseline values. If β is too low, the weather adjustment does not bring the weather-adjusted actual use per customer all the way up to baseline use per customer, which produces a surcharge to customers through the deferral mechanism.

Therefore, the way in which β might be influenced depends upon the forecast of weather conditions, or equivalently, whether the definition of HDD^N was influenced upward or downward. If winter weather is expected to be warmer than normal (or if it is expected to be normal, but HDD^N has been set too high), customers benefit if β is set too high and NW Natural benefits if β is set too low. Conversely, if winter weather is expected to be colder than normal (or if it is expected to be normal, but HDD^N has been set too low), customers benefit if β is set too low and NW Natural benefits if β is set too high.

As with the incentive to influence the definition of normal weather, the incentive to influence the weather sensitivity parameter is dramatically reduced when DMN is combined with WARM (and the incentive would be eliminated if the 90% factor on the deferral component of DMN were to be removed).

2.4.4 *Baseline Use per Customer*

Baseline use per customer is initially established through a rate case. Because of the methods associated with standard ratemaking (see Section 1), there is a history of contentiousness between regulators and utilities in determining forecast customer usage. In standard ratemaking, regulators can *reduce* customer rates by pursuing high short-term forecasts of customer usage, and utilities can *increase* rates by pursuing low forecasts of customer usage. (That is, once the revenue requirement is determined, rates are set by dividing revenue by forecast billing determinants.) The presence of DMN reduces these incentives, as the deferral component will tend to produce refunds to customers when baseline use per customer is set too low, and surcharges when baseline use per customer is set too high.

In the absence of DMN, any factor that is included in the forecast of customer usage that must itself be forecast (or assumed) can be manipulated to the benefit of either customers or the utility. In particular, note that forecasting customer usage requires an assumption regarding normal weather conditions. This provides a further incentive for the regulator to promote a normal weather definition that is too cold, as this will produce a baseline use per customer value that is too low, and lead to persistent refunds to customers. The incentive for the utility is the opposite.

Baseline use per customer and the baseline margin rate are jointly determined. If baseline use per customer is set too low, the margin rate will be set too high. Therefore, there are offsetting effects associated with influencing baseline use per customer. Setting baseline use per customer too low will lead to a margin rate that is too high, increasing revenues from the standard tariff. However, it will also lead to persistent refunds to customers through the DMN deferral mechanism.

In the absence of the 90% factor in the deferral mechanism, these two effects exactly offset one another, removing contentiousness over the value of baseline use per customer. In this case, the only effect of setting baseline use per customer incorrectly is that the change in revenues with respect to changes in usage (not due to weather or expected price effects) will be too high or too low because the margin rate will also deviate from its correct value. However, this does not benefit either customers or NW Natural on average, and all parties should be better off by setting the correct baseline value, ensuring that the revenue adjustments are of the appropriate magnitude.

2.5 Potential Improvements in the Mechanism

2.5.1 *Methods of Refunding or Collecting Deferral Account Funds*

Currently, DMN recovers revenue shortfalls or refunds excess revenues by adjusting the per-therm rate for the following year. There are two potential problems with this approach. First, it introduces the potential for customers to be credited or charged an incorrect share of the revenue adjustment. This would occur whenever a customer's share of total usage differs between the two years. Second, by rolling the adjustment into the per-therm rate, DMN alters the price signal to customers (albeit only slightly), changing the marginal incentives for increasing or decreasing usage.

An alternative that would address both of these concerns would be to calculate, for each month, the dollar amount that each customer should be credited (charged) based on current usage. That is, the calculation of the deferral amount would be identical to the current method. However, instead of calculating a change to the per-therm rate for the coming year, the deferral adjustment would be credited or charged to customers in a lump sum adjustment based on their share of class usage in that month.

There would then be several options for refunding (collecting) the deferral amounts. First, the credits (charges) could be applied to customers' current bills, which would have the added benefit of reducing cash flow risk for customers. Second, the credits (charges) could be refunded (collected) in a lump sum at the end of the year. However, customers may not find this alternative appealing in years in which they pay a large lump-sum charge. Third, the refunds (collections) could be spread across the twelve months of the following year.

It is possible that this alteration to DMN would increase the administrative costs of the rate. However, given the complexity of WARM, we believe that NW Natural's billing system would be able to accommodate the proposed changes. In addition, these changes would make DMN more visible to customers. Currently, DMN adjustments to rates are not separately listed on customer bills, which has reduced awareness of the mechanism and therefore (we expect) has reduced the number of customer service issues associated with DMN. Changing the way in which DMN adjustments are allocated and refunded (or recovered) will likely increase the awareness of DMN, which could lead to increased customer service expenses.

2.5.2 Incomplete Coverage

Removing the 90% factor applied to the deferral component would improve DMN's incentive properties (*i.e.*, it would further reduce NW Natural's disincentive to promote energy efficiency) and eliminate some incentives to game DMN parameter values. Given that this factor can help or harm customers (*i.e.*, it reduces both surcharges and refunds), it does not seem to serve any useful purpose and should be eliminated.

2.5.3 Complexity

Especially in combination with WARM, DMN is a complex mechanism to understand and communicate to others. A full decoupling mechanism, which produces nearly identical total revenue effects to the combination of DMN and WARM, requires the setting of fewer parameters, and is much more easily explained and understood. A more detailed discussion of the tradeoffs between DMN, WARM, and full decoupling is contained in Section 5.

3. WEATHER ADJUSTED RATE MECHANISM

3.1 Description of Mechanism

The Commission approved WARM in 2003 as a means of reducing weather-related risk for both NW Natural and its customers. That is, fixed distribution costs are recovered through volumetric rates, and customer usage is sensitive to weather conditions. Therefore, in cold winters when usage is above expected levels, NW Natural over-recovers distribution costs and customers' bills are higher than usual. Conversely, in mild winters, NW Natural under-recovers distribution costs and customers' bills are lower than usual. Because NW Natural's exposure to weather is the opposite of its customers (*i.e.*, when NW Natural is made worse off by weather, its customers are better off), mechanisms such as WARM can reduce risk for both parties. In 2004, WARM was altered in two ways. First, limits were placed on the size of the WARM adjustment in any one month (though the full adjustment is still recovered in subsequent months). Second, the calculation of the WARM adjustment was altered so that it is determined on a customer-specific basis instead of a class-wide basis. The description below is of the current form of WARM.

A discussion of WARM in this report is appropriate because the combination of WARM and DMN produce effects that are very similar to full decoupling, which was the initial proposal of NW Natural (in place of DMN). In addition, some aspects of DMN (*e.g.*, incentives to game parameter values) can only be fully understood by introducing WARM effects.

Equation 3 shows the formula used to calculate the WARM adjustment (prior to the application of maximum bill change provisions). It is calculated for each customer based on their billing cycle usage and weather data from the closest available weather station (among the eight established district weather stations used by NW Natural).

Equation 3: WARM Adjustment = $\Sigma_d (HDD^N{}_d - HDD^A{}_d) * \beta * M$.

In this equation, d indexes the days of the customer's billing month; $HDD^N{}_d$ is normal heating degree days (HDDs) for day d of the billing month, based on a 25-year average ending in 2000; $HDD^A{}_d$ is the actual heating degree days for day d of the billing month; β is the weather-sensitivity parameter (an estimate of the change in customer usage with respect to a one unit change in HDDs); and M is the distribution margin in dollars per therm.

β is statistically estimated as part of the class load forecasting process. Its units are in therms per HDD, and the same value for β is used for all customers within a class. For residential customers, the WARM adjustment is capped at the lesser of $12 or 25% of the volumetric portion of the bill. For commercial customers, the WARM adjustment is capped at the lesser of $35 or 25% of the volumetric portion of the bill. However, the portion of the WARM adjustment that exceeds the cap is collected in subsequent months. While WARM is the default service for residential and commercial customers, customers may opt out of the program.

3.2 Expected Risk Effects

From NW Natural's perspective, WARM is an effective means of reducing weather-related distribution cost recovery risk provided that few customers decide to opt out of the program. The effect of the opt-out provision upon NW Natural's risk depends upon the characteristics of the customers that opt out relative to those of the class. A more detailed discussion of the effects of the opt-out provision is included later in this section. Under the assumption that no customers opt out of the program, WARM will be effective in reducing NW Natural's weather risk provided that β accurately reflects the average customer response to weather variations, and that the definition of normal weather is correct.[10]

From a customer perspective, WARM is a less effective tool for reducing risk. This is because β is set on a class-wide basis and is constructed in units of therms per HDD. Thus, the amount of risk coverage varies across customers. Customers who are smaller or less weather sensitive than the class average are *over-insured* by WARM.[11] Conversely, customers who are larger or more weather sensitive than the class average are *under-insured* by WARM. The added provisions that cap the amount of the WARM adjustment in any month do not alter our conclusions about over- or under-insurance because the total WARM adjustment is collected from each customer in subsequent months. In Section 3.5 below we discuss the potential value of re-designing the weather adjustment parameter so that it is in units of *percentage* changes in therms per HDD.

3.3 Expected Incentive Effects

The WARM program does not alter NW Natural's behavioral incentives. This is because WARM affects only weather-related fluctuations in distribution revenues, and weather is out of NW Natural's control. The incentives to promote conservation, load growth, the addition of new customers, and the provision of high quality customer service are not affected.

WARM also does not affect participating customers' incentives. WARM may provide customers with benefits through a reduction in their bill variability, but the customers' marginal cost of changing usage levels is not affected by WARM.

3.4 Possibilities for Gaming the Mechanism

Neither the Commission nor NW Natural has an incentive for β to deviate from its true value. (This is true whether WARM is considered by itself or in combination with DMN.) Setting the value correctly ensures that the WARM adjustments have the appropriate magnitude. A value that is too high introduces more weather risk (relative to the "correct" value of β) for both NW Natural and its customers (on average). Setting β too low leads to an adjustment that under-insures NW Natural and its customers (on average).

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[10] However, if DMN and WARM use the same definition of normal weather, the errors in the revenue recovery for DMN and WARM due to an incorrect definition of normal weather largely cancel out. This reduces the incentive to "game" the definition of normal weather.

[11] Because WARM only intends to cover the risk associated with distribution fixed cost recovery, it is unlikely that customers will be over-insured against the weather risk associated with their *entire* bill. That is, any over-insurance on the distribution component will likely be smaller than the remaining weather risk on the energy component of the bill.

When WARM is considered by itself, the Commission and NW Natural have an incentive to manipulate the definition of normal heating degree days. Setting HDD^N below its "true" value leads to a situation in which, on average, WARM produces refunds to customers. (If HDD^N equals its true value, WARM will, over time, benefit neither NW Natural nor its customers.) Conversely, if HDD^N is set above its true value, WARM will tend to increase customers' bills.

However, when WARM is evaluated in combination with DMN, the incentive to game the definition of normal heating degree days is dramatically reduced, provided that both programs use the same definition. An example will help to illustrate this effect. To simplify the example, the timeframe of the analysis is reduced to one month and we will assume that the residential class consists of only one customer who uses 100 therms in normal weather conditions. Furthermore, we will assume that there is no price change (and therefore no elasticity adjustment to the baseline quantity), and that the customer does not deviate from its non-weather related usage. Consider the following case, in which the tariff value for HDD^N is higher than the true value, and actual heating degree days (HDD^A) match the true value:

"True" $HDD^N = 400$
Tariff $HDD^N = 500$
$HDD^A = 400$
$\beta = 0.1958$
$M = \$0.42569$

In this case, both the "true" WARM and DMN adjustments are zero. That is, weather is at normal conditions and there is no non-weather related usage change, so the mechanisms do not affect revenue collection. However, because the tariff contains an incorrect value of HDD^N, both DMN and WARM lead to non-zero adjustments, as shown below.

DMN deferral amount = $90\% * (QPC^{B,P} - Q^{WN}/C) * M * C$
$Q^{WN} = Q^{A,S} + \beta * \Sigma_d (HDD^N{}_d - HDD^A{}_d) = 100 + 0.1958 * (500 - 400) = 119.58$
DMN deferral amount = $90\% * (100 - 119.58) * \$0.42569 * 1 = -\$7.50$
WARM adj. = $\Sigma_d (HDD^N{}_d - HDD^A{}_d) * \beta * M = (500 - 400) * 0.1958 * \$0.42569 = \$8.34$

These equations show that, while WARM over-collects by $8.34, DMN offsets 90% of the over-collection, so that the net over-collection is only $0.83. Assuming that the intended distribution margin recovery is equal to $Q^{B,P} * M = \$42.57$, the over-collection amounts to only about 2% of the distribution revenue requirement, versus about 20% when considering WARM by itself. This demonstrates how the combination of DMN and WARM reduces the incentive to game the definition of normal weather.

This example highlights an additional incentive problem caused by setting HDD^N too high. That is, given that customers may opt out of WARM, setting HDD^N too high provides customers with an opportunity to game rates. If the customer realizes that WARM is established in way that consistently produces surcharges to their bills, they will rationally opt out of the program. This decreases the effectiveness of WARM in reducing weather risk, and negates the offsetting effects of DMN and WARM described above. In the example above, if the customer opts out of WARM, the \$7.50 refund produced by DMN remains, but the offsetting surcharge of \$8.34 generated by WARM is lost, leaving NW Natural with reduced overall revenues. (Alternatively, if HDD^N were set too low, rational customers would not opt out of WARM, as its persistent refunds would offset the persistent surcharges created by DMN, which does not allow them to opt out.) This example therefore highlights the beneficial effects of combining DMN and WARM in terms of compensating for inaccuracy in the program parameters.

3.5 Potential Improvements in the Mechanism

The use of a class-wide value of β reduces the economic value of WARM for many customers, increasing the potential that customers will opt out of WARM. NW Natural's benefits from WARM decline when customers opt out of WARM.

Two options exist for addressing this problem. First, NW Natural could continue to use a class-wide value of β, but instead calculate it as a *percentage* change in the usage per HDD. This would address the customer size problem (that small customers tend to be over-insured by WARM in its current form). For example, if β were expressed in percentage terms, smaller customers would experience lower WARM adjustments to their bill than under the current system.

The second option is to calculate *customer-specific* values of β for use in calculating the WARM adjustments. (These could either be in percentage or level terms.) This approach would address two problems: the inaccurate treatment of customers with respect to size, and the inaccurate treatment of customers with respect to weather sensitivity. Calculating customer specific β parameters would also have the effect of automatically excluding non-weather sensitive customers from the WARM program.

CAEC has developed software that is capable of calculating customer-specific values of β.[12] The software requires twelve months of billing data for a customer in order to estimate β, and screens are used to weed out "bad" estimates. Therefore, if WARM is modified to use an algorithm such as this, the program would be limited to customers with sufficient billing data (at their current site) and for whom the statistical model provides a reliable estimate of weather sensitivity.

A more complete analysis of the implications of modifying the WARM program will be performed in a subsequent report.

4. EVIDENCE OF DMN EFFECTS

Sections 2 and 3 presented theoretical discussions of the expected effects of DMN and WARM. This section explores the extent to which evidence may be found that is consistent with the theoretically expected effects of DMN. In addition, this section discusses the three programs funded by the Public Purposes Funding approved along with

[12] The software has been used to calculate offers for fixed bill programs.

DMN: the Energy Trust of Oregon administered energy efficiency programs (specifically, the residential high-efficiency furnace program), the Oregon Low-Income Energy Efficiency Program (OLIEE), and the Oregon Low-Income Gas Assistance Program (OLGA).

4.1 "Back Cast" of DMN Financial Effects from 1993 to 2004

The financial effects of DMN can be divided into two categories: the price elasticity effect and the deferral component. The price elasticity effect is equal to the change in the per therm margin multiplied by total class usage. That is, as natural gas prices increase, the baseline usage is adjusted downward and the dollar per therm margin is adjusted upwards, so that the margin *multiplied* by baseline usage per customer remains constant (all else equal). This portion of the adjustment is intended to adjust revenues for changes in use per customer that occur because of changes in energy prices.

The deferral component is intended to adjust revenue recovery for 90% of the non-weather driven fluctuations in use per customer. Deferral revenues can be caused by changes in use per customer due to conservation efforts, an imperfect price elasticity adjustment, or simply random factors. The deferral amount is calculated as 90% of the difference between the price-adjusted baseline usage and the weather-adjusted actual usage, multiplied by the adjusted dollar per therm margin.[13] Table 4-1 below shows the dollar amounts associated with these two categories of revenue effects by customer class for the first two full years of DMN.

The first year of DMN, October 2002 through September 2003, contained large revenue effects because of the need to "catch up" with respect to substantial price increases (and therefore substantial load decreases) since the previous rate case. The following year, October 2002 through September 2003, experienced much smaller revenue adjustments because the baseline values were based on a rate case that concluded in 2003.

Table 4-1: Revenue Effects of DMN Mechanism: October 2002 through September 2004

Time Period	Customer Class	Elasticity Effect ($000)	Deferral ($000)	Total ($000)
Oct. 2002 to Sep. 2003	Residential	7,665	3,093	10,758
	Commercial	2,529	1,573	4,102
	Total	10,194	4,666	14,860
Oct. 2003 to Sep. 2004	Residential	940	-788	152
	Commercial	335	91	426
	Total	1,275	-697	578

Notes: positive values indicate surcharges to customers and negative values indicate refunds to customers.

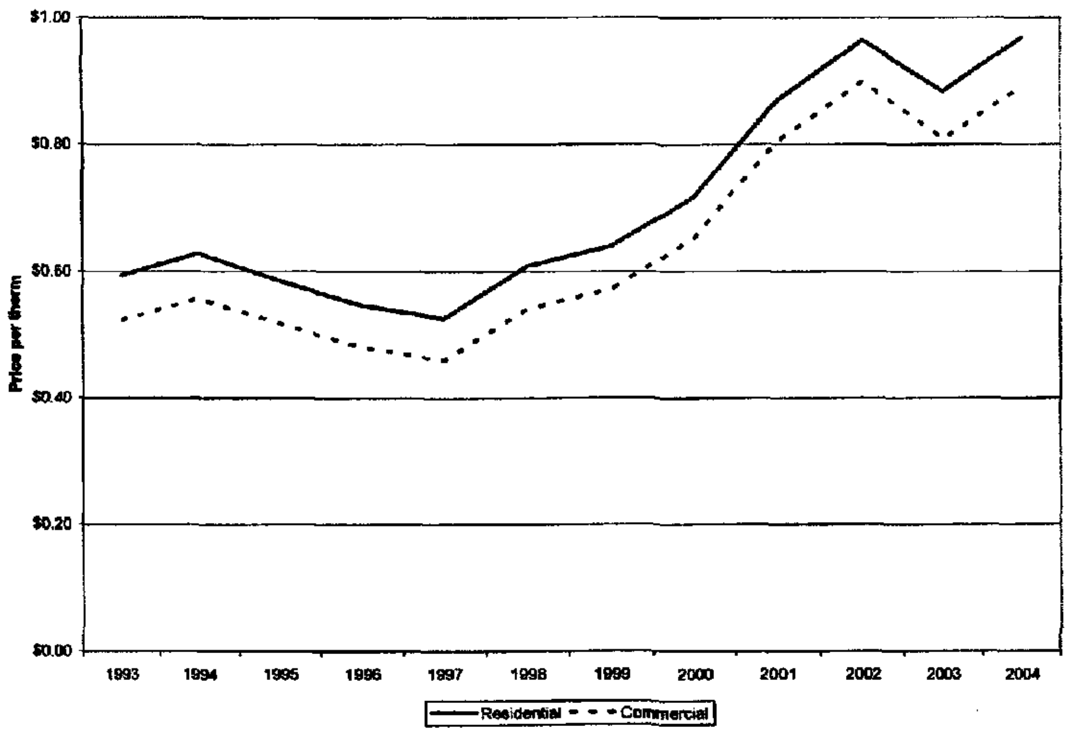
[13] Section 2.1 specifies the elasticity adjustment and deferral component in equation form.

Because DMN was approved relatively recently, there is a limited amount of direct experience to examine. In order to determine how DMN might function under a wider range of possible outcomes (*e.g.*, when prices are decreasing as well as increasing), we performed a "back cast" of DMN financial outcomes using annual data from 1993 through 2004. That is, we calculated the amounts of the price elasticity adjustment and deferral amounts for each of those years, at the price and weather conditions in those years, and using 2000 values of price and use per customer as baseline values. In order to facilitate this simulation, we made the following simplifying assumptions:

- We used annual data (*i.e.*, from January through December) as opposed to October through September monthly data.
- For the commercial class, we used Schedule 3 prices throughout instead of blending the price across the applicable commercial schedules. These prices are used to determine the percentage change in price that, combined with the price elasticity, determines the adjustment to baseline use per customer and margin rate.
- "Normal Weather" was defined as the average HDD value across the 12-year sample timeframe. This allows us to ignore issues about the "correct" definition of normal weather, as we use the *ex post* actual average value for this time period.
- Calendar year 2000 was set as the baseline year for use per customer (which is then weather normalized). Using 2000 as the baseline year allows us to examine DMN effects in years of flat or rising use per customer (prior to 2000), as well as declining use per customer (after 2000)
- The baseline dollar per therm margin was set as the October 2002 through September 2003 actual value, or \$0.34055 for residential customers and \$0.21692 for commercial customers. These values were simply used to provide an appropriate scale for the financial outcomes.
- The price elasticities and β coefficients (which define the change in use per customer per change in HDD and were used in weather normalization) are based on the values used in the actual DMN (and WARM) calculations. Specifically, the residential price elasticity is -0.172, the commercial price elasticity is -0.110, the residential $\beta = 0.1958$, and the commercial $\beta = 0.7669$.

Figure 4-1 shows the residential and commercial prices for each year. Using a base year of 2000 for this analysis allows us to examine outcomes when the price is below the baseline value (prior to 2000) and above the baseline value (after 2000).

Figure 4-1: Residential and Commercial Prices: 1993 to 2004



Figures 4-2 and 4-3 show the annual DMN revenue adjustments for the residential and commercial classes, respectively. The results for each year consist of three bars. The first bar shows the deferral revenues, the second bar shows the price elasticity adjustment, and the third bar shows the total DMN revenue adjustment (*i.e.*, the sum of the other two bars).[14] Positive values indicate surcharges to customers and negative values represent refunds to customers. Notice that there are no DMN adjustments for the year 2000 because it is the base year.

Figure 4-4 shows residential and commercial weather-normalized use per customer. In both cases, use per customer is declining over time, with 2000 as a transitional year between high and low values. This is reflected in the DMN revenue adjustments shown in Figures 4-2 and 4-3, in which pre-2000 adjustments are negative (refunds to customers), and post-2000 adjustments are positive (surcharges to customers).

[14] A spreadsheet containing the underlying data and calculations is available from the authors.

Figure 4-2: Simulated Residential DMN Revenue Adjustments: 1993 to 2004

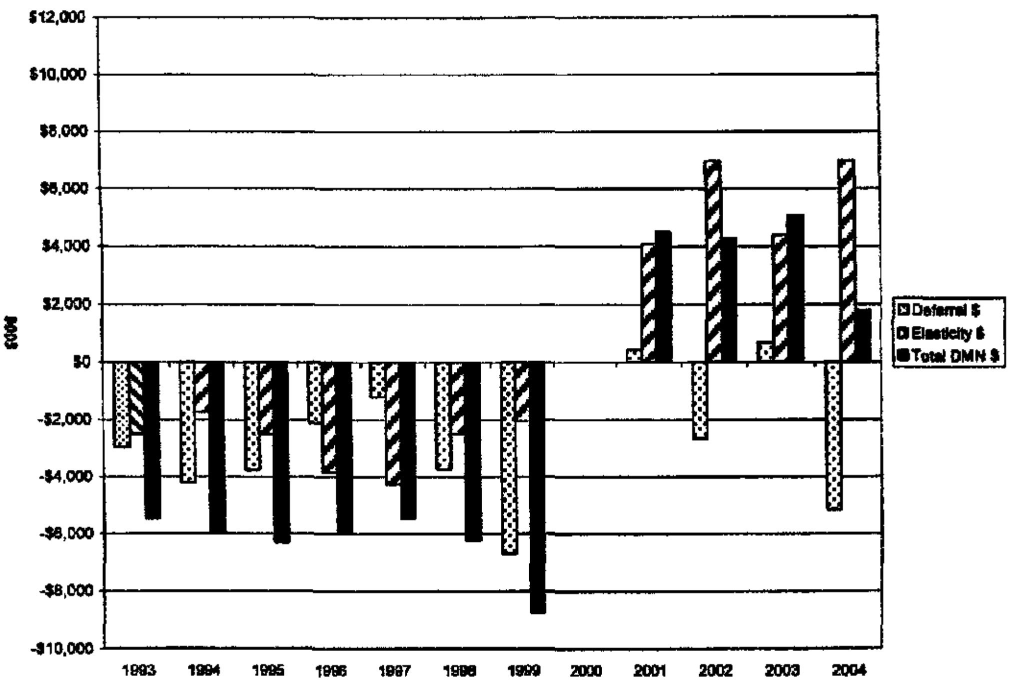


Figure 4-3: Simulated Commercial DMN Revenue Adjustments: 1993 to 2004

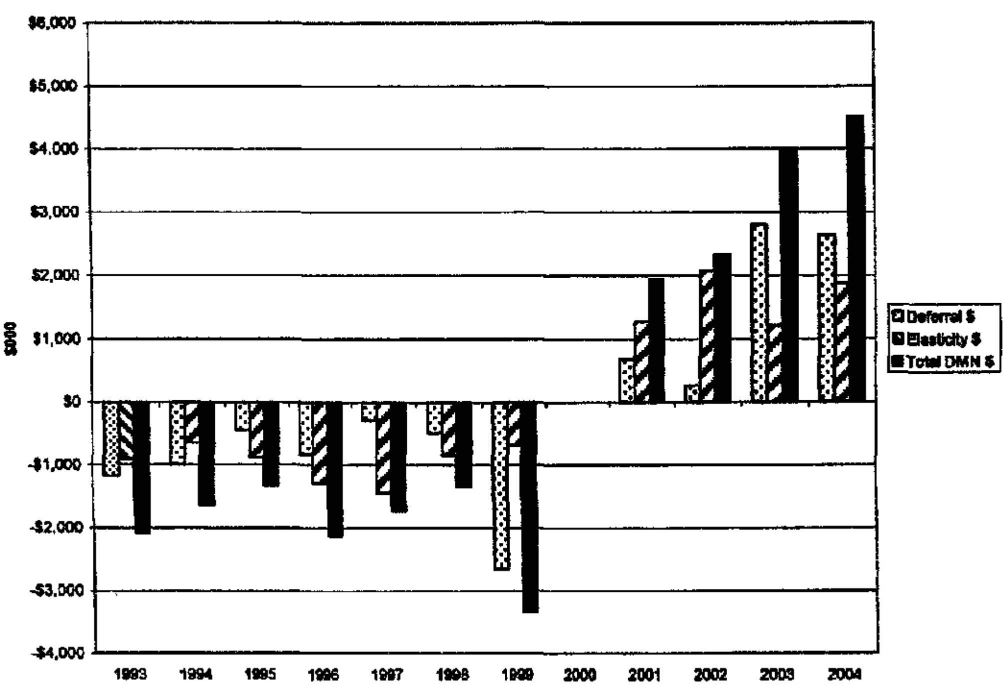
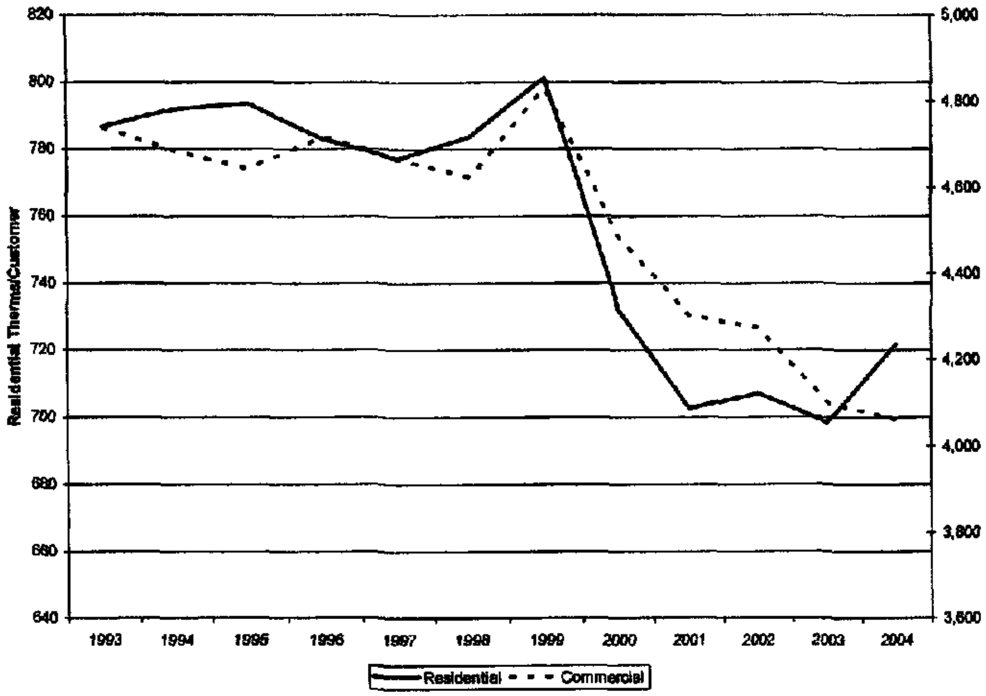


Figure 4-4: Residential and Commercial Weather-Normalized Use per Customer:
1993 to 2004



An examination of the margin recovery per customer with and without DMN shows that DMN reduces the variability. For residential customers, DMN reduces the standard deviation of per-customer margins across the simulated years by 30%. For commercial customers, DMN reduces the standard deviation of per-customer margins across the simulated years by 42%. This is the effect that we expected to observe, and the magnitude indicates the effect of implementing DMN instead of full decoupling, which would produce a 100% reduction in the standard deviation of per-customer margins.

One surprising aspect of Figures 4-2 and 4-3 is the size of the deferrals with respect to the elasticity revenue adjustments. That is, we might expect that the price elasticity adjustment would account for the majority of the revenue effects associated with the change in use per customer, leaving a relatively small amount to be "cleaned up" by the deferral mechanism. However, in several years (*e.g.*, 1993 and 1994), the deferral revenues actually exceed the elasticity adjustment revenues.

A closer inspection of the DMN calculations reveals a potential explanation for this effect. Figures 4-5 and 4-6 illustrate the price-adjusted baseline use per customer and weather-adjusted actual use per customer for the residential and commercial classes, respectively. The two figures tell a similar story, with price-adjusted baseline use per customer lying below weather-adjusted actual use per customer in the early years (in

Figure 4-5: Residential Price-Adjusted Baseline and Weather-Normalized Use per Customer: 1993 to 2004

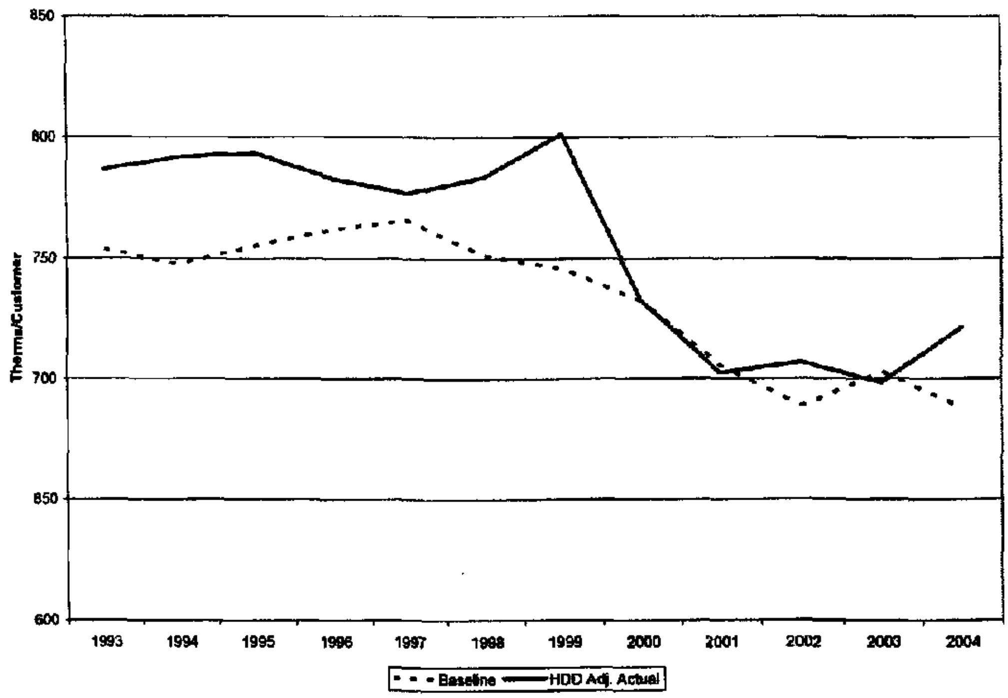
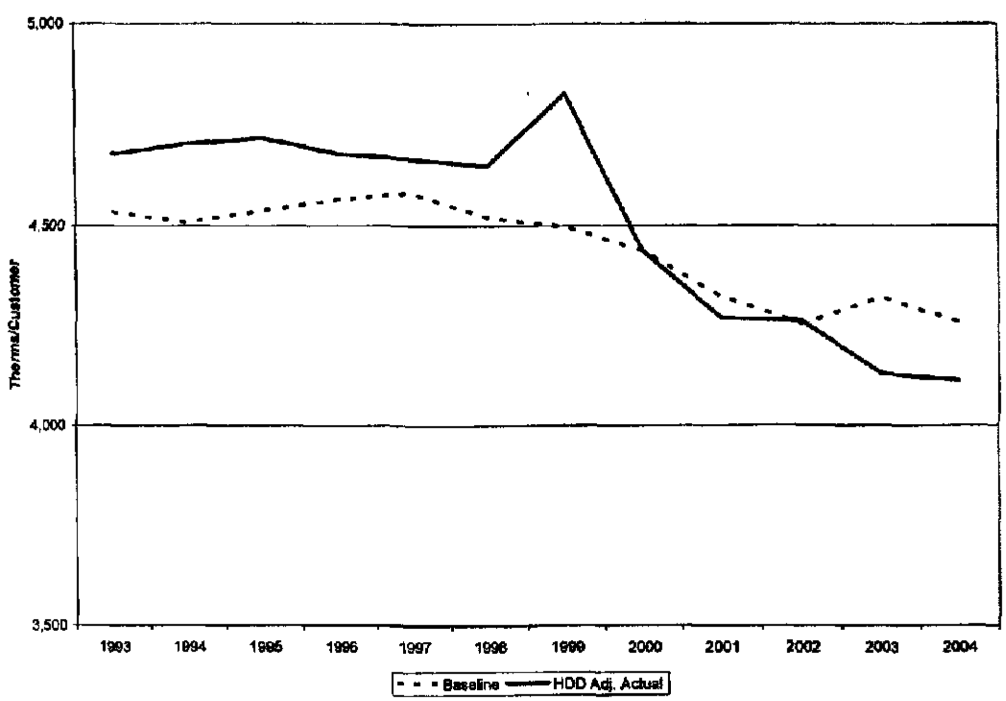


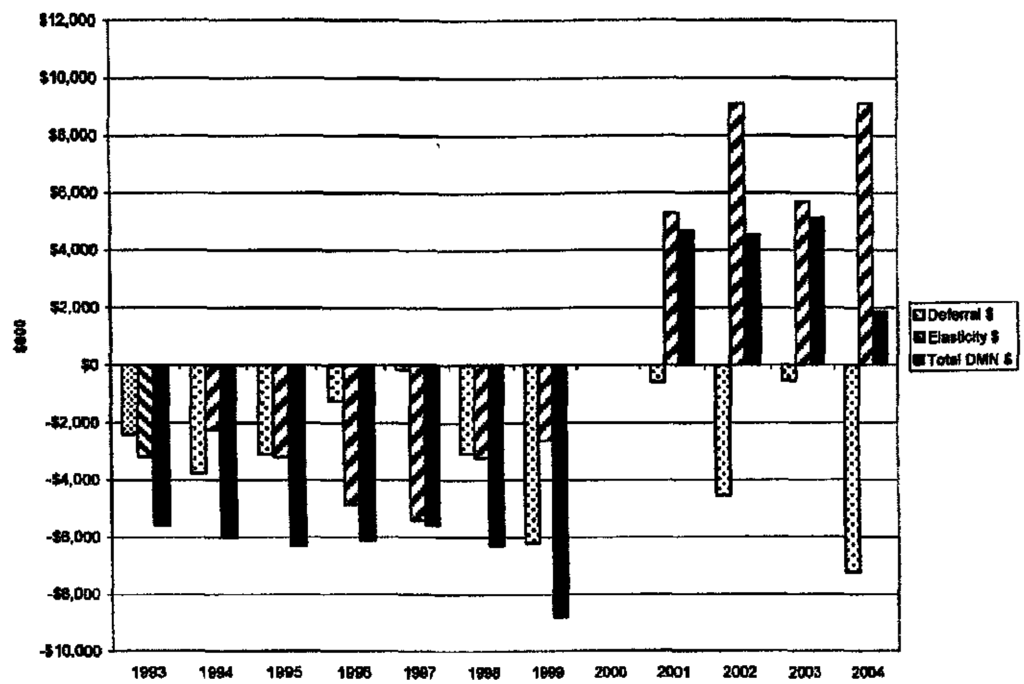
Figure 4-6: Commercial Price-Adjusted Baseline and Weather-Normalized Use per Customer: 1993 to 2004



which prices are low relative to 2000). This could indicate that the stipulated price elasticity values are too low (in absolute value). That is, under the assumption of a higher price elasticity, the usage changes would be larger for a given price difference. This would have the effect of bringing the baseline curves closer to the weather-adjusted actual curves.[15]

We estimated the price elasticities that would minimize the difference between price-adjusted and weather-normalized actual use per customer for each class.[16] Figures 4-7 and 4-8 show the deferral and price elasticity revenue adjustments using the "calibrated" price elasticity values.

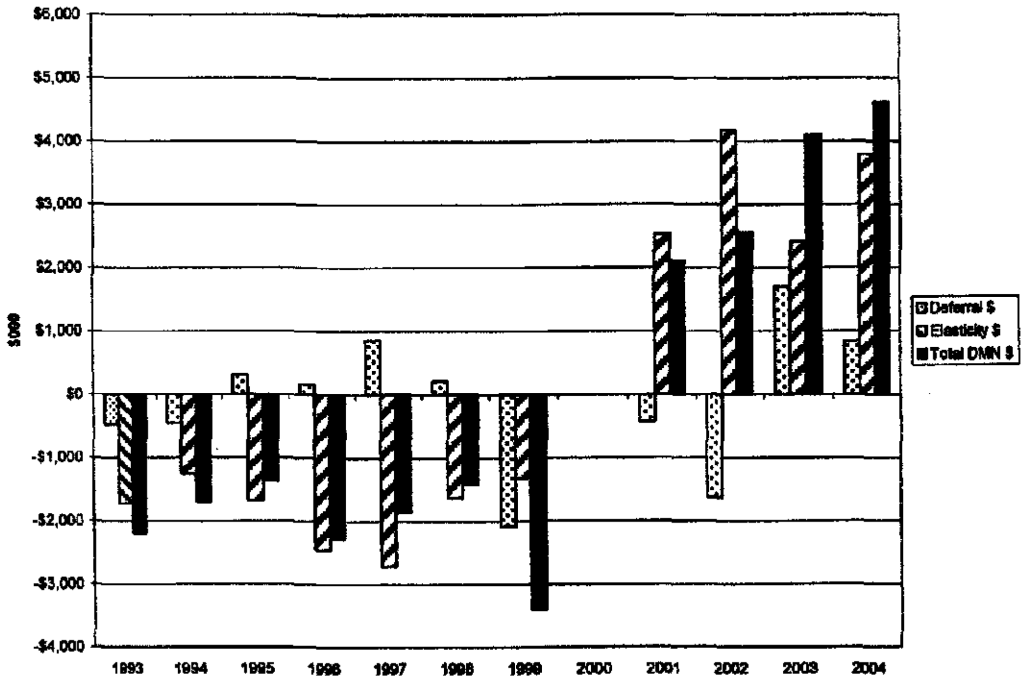
Figure 4-7: Simulated Residential DMN Revenue Adjustments Using Calibrated Price Elasticity: 1993 to 2004



[15] The weather-adjustment parameter (β) is another potential culprit. Our research indicates that "errors" in the value of β contribute to the high level in deferrals in the residential class, but not in the commercial class.

[16] This was done by setting the price elasticity to minimize the sum of squared differences between price-adjusted baseline and weather-adjusted actual use per customer. The weather-adjustment parameters (β) are held at its tariff values for this exercise.

Figure 4-8: Simulated Commercial DMN Revenue Adjustments Using Calibrated Price Elasticity: 1993 to 2004



A comparison of Figure 4-7 to Figure 4-2 (the initial residential deferral and price elasticity adjustment revenues); and of Figure 4-8 to Figure 4-3 shows that calibrating the price elasticity value tends to increase the size of the price elasticity revenue adjustment compared to the deferral amounts. This effect is larger in the commercial class, in which the price elasticity calibration produced a larger change in the price elasticity. The calibrated residential price elasticity is -0.221, compared to the stipulated value of -0.172; and the calibrated commercial price elasticity is -0.213, compared to the stipulate value of -0.110. Note that these values were created to illustrate how the DMN revenue adjustments change as the price elasticity changes. While we believe that this section provides an indication that the stipulated price elasticities may be too low, we do not necessarily recommend using this calibration method to revise the price elasticities. A more reliable method would be estimate the price elasticities directly from historical data, including use per customer, price, and weather data.

4.1.1 Conclusions

We draw two primary conclusions from this analysis. First, DMN revenue adjustments produce adjustments in the intended direction. That is, when non-weather adjusted use per customer increases (primarily because of a response to price decreases), DMN produces refunds to customers. Alternatively, when non-weather use per customer decreases (primarily because of a response to price increases), DMN leads to surcharges to customers. This has the effect of reducing the variability in margin recovered per customer.

The second conclusion that we take from this analysis is that NW Natural and the Commission should investigate whether the price elasticity values should be modified. There is some indication from this analysis that they are set too low (in absolute value), which could lead to relatively large deferrals. Setting the price elasticities "correctly" will minimize deferrals and prevent the 10% slippage of revenues built into DMN (which can work for or against customers).

4.2 Comparison of Revenue Variability across Natural Gas Utilities

One goal of DMN is to reduce the variability of commercial and residential distribution revenues. The Commission Staff requested an examination of NW Natural's revenue variability compared to that of a representative sample of utilities. The sample used here corresponds to the sample used to determine return on equity in NW Natural's last rate case (UG-152). It consists of the following utilities:

1. AGL Resources
2. Atmos Energy
3. Cascade Natural Gas
4. Energen
5. Laclede Gas
6. Nicor
7. NW Natural Gas
8. Peoples Energy
9. Piedmont Natural Gas
10. SEMCO Energy
11. Southwest Gas
12. WGL Holdings

The data were obtained from annual reports and SEC 10-K filings available on the corporate websites. The following information was collected for the years 1993 through 2004 (in most cases, not all years were available):

- Number of residential accounts (expressed either as the number of customers at year-end, or average number of customers during the year)
- Number of commercial accounts (expressed either as the number of customers at year-end, or the average number of customers during the year)
- Residential natural gas sales (expressed in either MDth or MMcf)
- Commercial natural gas sales (expressed in either MDth or MMcf)
- Residential operating revenues
- Commercial operating revenues
- Annual heating degree days

Appendix Table A1 contains all of the data that we were able to collect for the sample utilities. Figures 4-9 through 4-11 present comparisons of the variability of various measures across the utilities. Figure 4-9 compares residential and commercial operating revenues across utilities, expressed as a coefficient of variation (*i.e.*, the standard deviation of revenues divided by the mean, which facilitates comparisons across utilities of different sizes). Eleven of the twelve utilities had sufficient data for inclusion in this figure, though the period of available data varies across utilities.

Figure 4-9: Variability of Residential and Commercial Operating Revenues

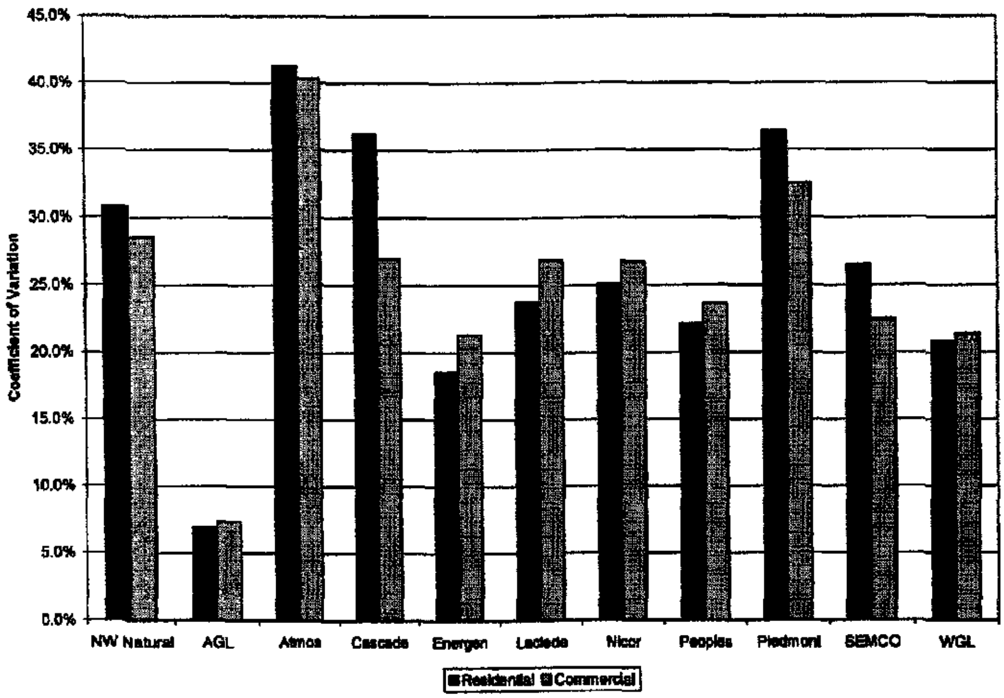


Figure 4-10 compares the variation of residential and commercial sales per customer across utilities. This comparison removes tariff price differences, allowing for an examination of variability differences that are driven only by fluctuations in use per customer. Because several utilities do not report the number of customers by rate class, only eight of the twelve utilities are included in this figure.

Figure 4-11 examines the variation in heating degree days (HDD) across utilities. This is a potentially useful comparison because weather is a primary driver of fluctuations in use per customer across years. In this case, we express variability as the standard deviation of annual HDD.

The information presented here provides mixed evidence regarding NW Natural's revenue variability as compared to other utilities. In terms of class operating revenues, NW Natural's variability is among the highest of the group. However, an examination of the underlying drivers of revenue variability in Figures 4-10 and 4-11 (sales per customer and heating degree days, respectively) reveals that NW Natural's variability is toward to low end of the sampled utilities.

Figure 4-10: Variability of Residential and Commercial Sales per Customer

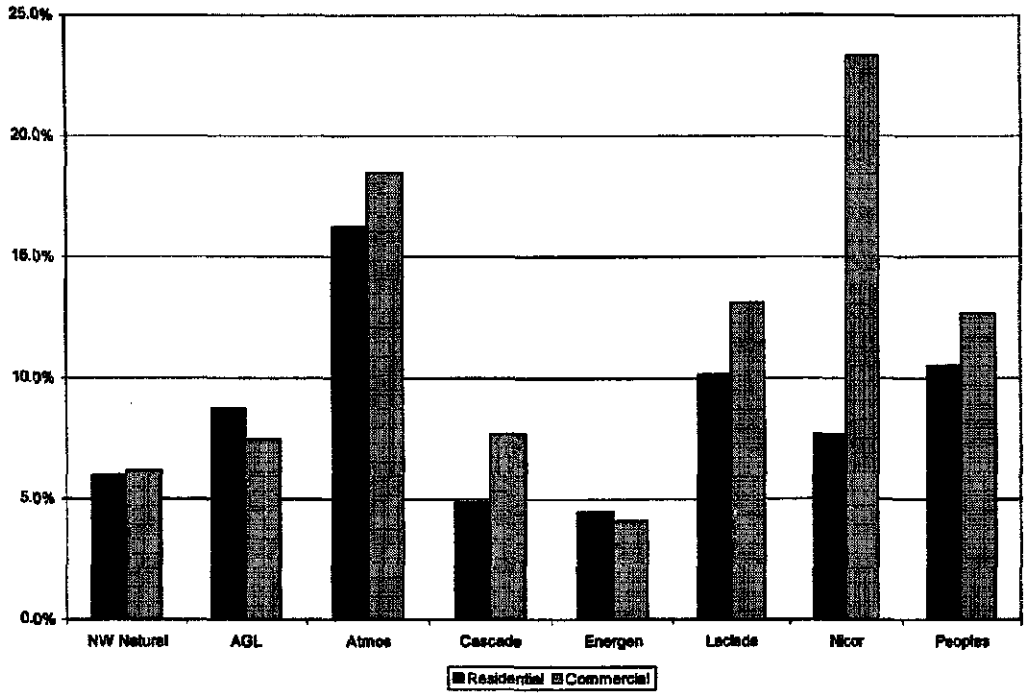
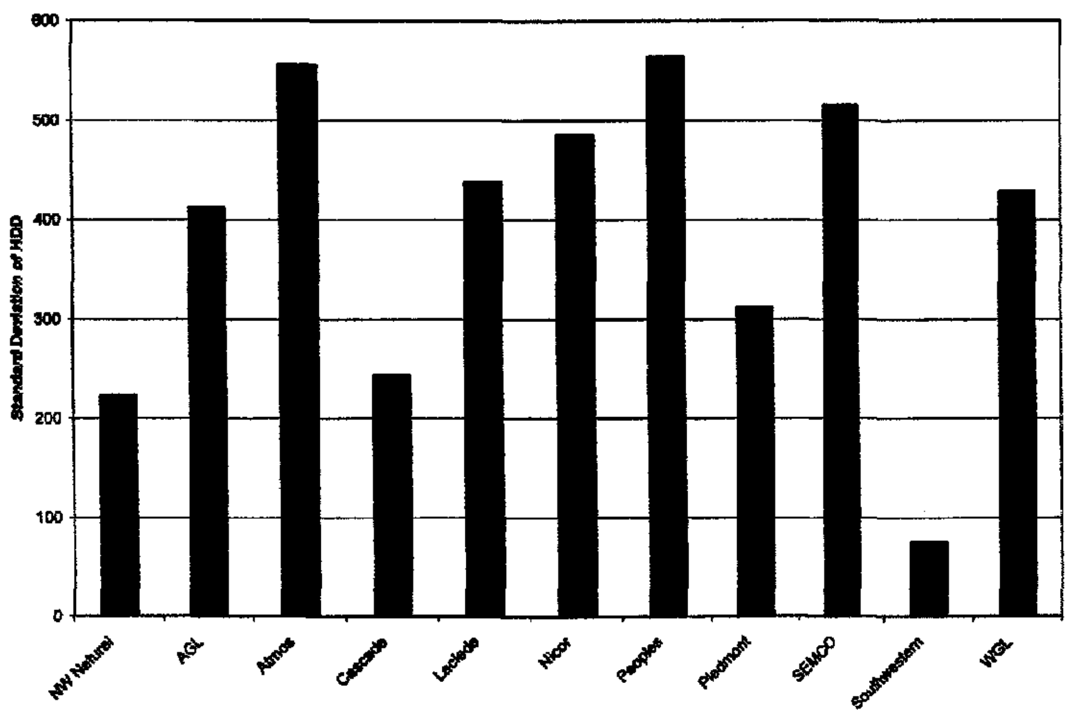


Figure 4-11: Variability of Heating Degree Days



This discrepancy appears to be due to NW Natural's relatively high growth in the number of customers. That is, as the number of customers increases, revenues increase as well. This increases the standard deviation of revenues over the sample time frame. To illustrate this point, note that three utilities had a higher standard deviation of residential revenues (shown in Figure 4-10): Atmos Energy, Piedmont Natural Gas, and Cascade Natural Gas. These same three utilities are the only utilities that had a higher growth rate in the number of residential customers than NW Natural during the sample period.

Note that the variability in use per customer is most relevant in the context of DMN. That is, the majority of the DMN revenue adjustments are due to fluctuations in use per customer. DMN affects revenues associated with a change in the number of customers only to the extent that the average size of new connections customers differs from the baseline use per customer. Therefore, based on the information in Figure 4-10, we conclude that NW Natural has a lower than average variation in distribution fixed cost recovery due to fluctuations in usage per customer.

4.3 Econometric Analysis of Use per Customer

The Commission Staff requested that we investigate the share of DMN revenue adjustments that are attributed to conservation, price elasticity effects, and economic activity. Unfortunately, because changes in use per customer are not directly assigned to these categories, this task cannot be accomplished using a simple accounting exercise. For example, if use per customer goes down during a time in which both the retail price and the unemployment rate increases, we must perform a statistical study to determine the relative influences of these factors.

This section performs that statistical study using historical data to assess the sources of variations in annual use per customer from 1993 through 2004. The results will allow us to infer the major sources of DMN revenue adjustments.

We examined residential and commercial customers separately. The analysis was conducted using ordinary least squares (OLS) regression analysis, which is a statistical technique that estimates the effect that *independent* (or explanatory) variables have on a *dependent* variable, which in this case is use per customer. The independent variables that were considered include:

- Annual heating degree days (HDD)[17];
- Price in dollars per therm;
- Oregon unemployment rate;
- Cumulative units adopted under NW Natural's High Efficiency Furnace (HEF) Program (used in the residential analysis only); and
- A time trend variable to account for changes over time in building codes, housing types, or appliance stock.

[17] HDD is calculated using a 59 degree base for residential customers and a 58 degree base for commercial customers. We use the weighted average HDDs across NW Natural's seven districts, where the weights are set according to each district's share of total customers.

Tables 4-2 and 4-3 present the OLS coefficient estimates for residential and commercial customers, respectively. Three sets of results are presented for each customer class, which differ according to the independent variables that were included in the regression equation. The model used in the first column of each table includes all independent variables, the model used in the second column excludes the time trend variable, and the model used in the third column includes only the weather and price variables (*i.e.*, HDD and price).

Table 4-2: OLS Estimates of Residential Usage per Customer from 1993-2004

Variable	All Variables	No Time Trend	Only HDD, Price
	(1)	(2)	(3)
HDD	0.166** (0.040)	0.152** (0.033)	0.161** (0.028)
Price	-173.0 (108.8)	-151.4 (99.3)	-224.4** (34.0)
Unemployment Rate	-4.392 (12.386)	1.759 (7.700)	n/a
HEF Adoptions	0.0011 (0.0036)	-0.0011 (0.0013)	n/a
Time trend	-6.226 (9.539)	n/a	n/a
Constant	475.3** (107.0)	449.1** (95.0)	472.0** (83.9)
R-squared	0.921	0.915	0.907

Notes: The number of observations = 12. The dependent variable is residential use per customer in therms. Standard errors are in parentheses. ** denotes that the variable is statistically significant at the 5 percent level. * denotes that the variable is statistically significant at the 10 percent level.

4.3.1 Residential Results

As Table 4-2 shows, the independent variables explained a very high percentage of the variation in residential usage per customer, with R-squared values ranging from 0.907 to 0.921.[18] Weather, represented by HDD, was a statistically significant determinant of usage per customer in each column. The estimated coefficient for HDD is interpreted as follows: a one unit increase in annual HDD leads to an increase in residential therms per customer of about 0.16.

[18] R-squared values range from zero to one, with zero indicating that the model has no explanatory power, and one indicating that the model explains all of the variation in the dependent variable.

Table 4-3: OLS Estimates of Commercial Use per Customer from 1993-2004

Variable	All Variables	No Time Trend	Only HDD, Price
	(1)	(2)	(3)
HDD	0.983** (0.180)	1.004** (0.177)	0.979** (0.169)
Price	-939.3* (476.5)	-1,299.7** (271.5)	-1,431.1** (202.2)
Unemployment Rate	-36.39 (41.82)	-30.71 (40.99)	n/a
Time trend	-17.78 (19.23)	n/a	n/a
Constant	2,970.1** (482.3)	2,997.1** (477.1)	2,954.1** (461.9)
R-squared	0.927	0.918	0.912

Notes: The number of observations = 12. The dependent variable is commercial use per customer in therms. Standard errors are in parentheses. ** denotes that the variable is statistically significant at the 5 percent level. * denotes that the variable is statistically significant at the 10 percent level.

The price per therm, unemployment rate, and cumulative HEF adoption variables were highly correlated with the time trend variable, which makes the interpretation of their coefficients somewhat more complex. That is, the time trend variable is intended to pick up exogenous changes in use per customer over time (*i.e.*, those changes that cannot be directly attributed to weather, price, economic conditions, or NW Natural conservation efforts). However, because natural gas prices and HEF adoptions increase steadily during the analysis time period (this is true to a lesser extent for the unemployment rate), it is difficult for the regression model to differentiate changes in use per customer that might be attributed independently to any one of the factors.

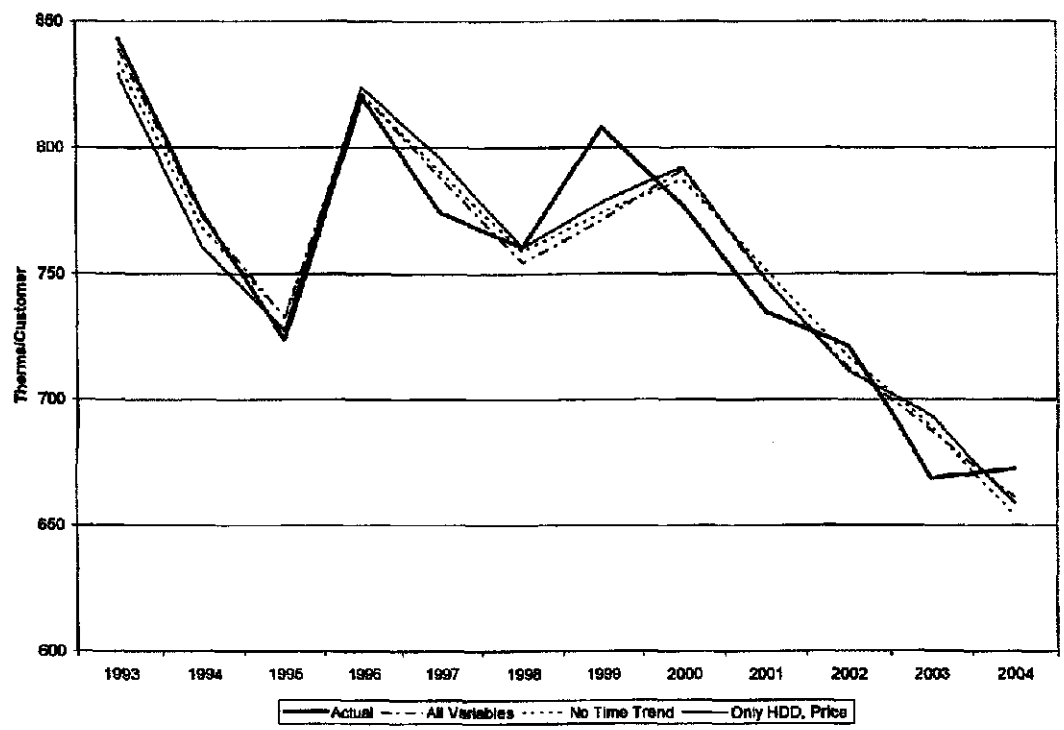
In the full specification, shown in column 1 of Table 4-2, the price variable was the non-weather variable closest to meeting the standard definition of statistical significance.[19] The HEF adoptions coefficient does not have the sign predicted by theory (the result implies that residential use per customer increases as HEF adoptions increase), and is not statistically significant. The coefficient on the Oregon unemployment rate has a very high standard error, and is therefore not statistically significantly different from zero. The time trend coefficient is negative (implying that usage per customer has been declining over time, all else equal), but is not statistically significant.

[19] In regression analysis, the statistical significance of estimated coefficients is evaluated as follows: the null hypothesis is that the estimated coefficient is equal to zero. This hypothesis is tested using the *t*-statistic, which is calculated by dividing the coefficient by its standard error. Using the *t*-statistic, the number of observations, and the number of variables included in the model, the *p-value* is obtained, which is the probability of observing the outcome if the null hypothesis is true. For example, when evaluating a coefficient, a p-value of 5 percent means that there is only a 5 percent chance that we would observe the estimated coefficient if the true value is equal to zero. Traditionally, a 5 percent p-value threshold is considered highly statistically significant, and a 10 percent p-value threshold is considered to be marginally statistically significant.

In an attempt to disentangle the effects of these variables, we first excluded the time trend variable, the results of which are contained in column 2. When we did this, the standard errors of estimated coefficients for price, the unemployment rate, and HEF adoptions all decreased, indicating an increase in the statistical significance of the estimated coefficients. However, aside from the significant HDD coefficient, only the price coefficient was close to being statistically significantly different from zero. Because of this, we include column 3, which shows the results when only HDD and price were included as independent variables. Notice that the R-squared value did not drop substantially, with over 90% of the variation in residential use per customer explained by only these two variables.

Figure 4-12 illustrates the high explanatory power of these regression equations. The bold line shows actual residential use per customer from 1993 through 2004. The three remaining lines show the values predicted by the regression equations. That is, each point in the figure was calculated by multiplying the estimated coefficients by the actual values for the included variables (*e.g.*, HDD or the price) and adding the estimated constant. Each of the three regression models closely tracks actual use per customer. In particular, notice that including variables beyond HDD and the price does not produce large changes in the predicted values.

Figure 4-12: Actual versus Predicted Residential Use per Customer



4.3.2 Commercial Results

As Table 4-3 shows, the results for the commercial customers resemble those of the residential customers in that the independent variables explained a very high percentage of the variation in use per customer. (R-squared values range from 0.912 to 0.927.) In addition, weather was a statistically significant determinant of use per customer in each of the three estimated models. The estimated coefficient for HDD is interpreted as follows: a one unit increase in annual HDD leads to an increase in commercial therms per customer of about 0.98.

The commercial customer data displayed the same high correlation between the time trend and the non-weather independent variables as the residential customer data. We performed a similar set of regression models in an attempt to determine the drivers of use per customer. (However, there is no commercial class equivalent to HEF adoptions.) Among the non-weather variables in the full specification, shown in column 1 of Table 4-3, only the price coefficient is (marginally) statistically significant (though the coefficient on the unemployment rate and the time trend have the theoretically predicted or expected sign).

When we excluded the time trend variable in column 2, the estimated coefficient for the price variable was highly statistically significant, while the estimated coefficient for the unemployment rate did not improve (in terms of an increase in the ratio of the coefficient to its standard error, which is referred to as the *t-statistic*). Because of this, we included column 3, which shows the results when only HDD and price are included as independent variables. Notice that the R-squared value does not drop substantially, with over 90% of the variation in commercial use per customer explained by only these two variables.

Figure 4-13 parallels Figure 4-12, illustrating the high explanatory power of these regression equations. The bold line shows actual commercial use per customer from 1993 through 2004 and the three remaining lines show the values predicted by the regression equations. Once again each of the three regression models closely tracks actual use per customer, and including variables beyond HDD and the price does not lead to large changes in the predicted values.

4.3.3 Implications of the Results

We draw three major conclusions from this analysis.

1. Weather (HDD) and price were the major drivers of changes in residential and commercial use per customer over the time period of the analysis. Table 4-4 illustrates the magnitudes of these effects. The upper portion of the table shows that residential use per customer (unadjusted for weather, prices, or economic conditions) has dropped from 843 to 673 therms per year between 1993 and 2004. Based on our regression estimates, we attribute 51 percent (or 86 therms) of this change to differences in weather conditions, and 49 percent (or 84 therms) to an increase in the price. According to this simple decomposition, there is virtually no change in use per customer that is not explained by changes in weather and prices.

Figure 4-13: Actual versus Predicted Commercial Use per Customer

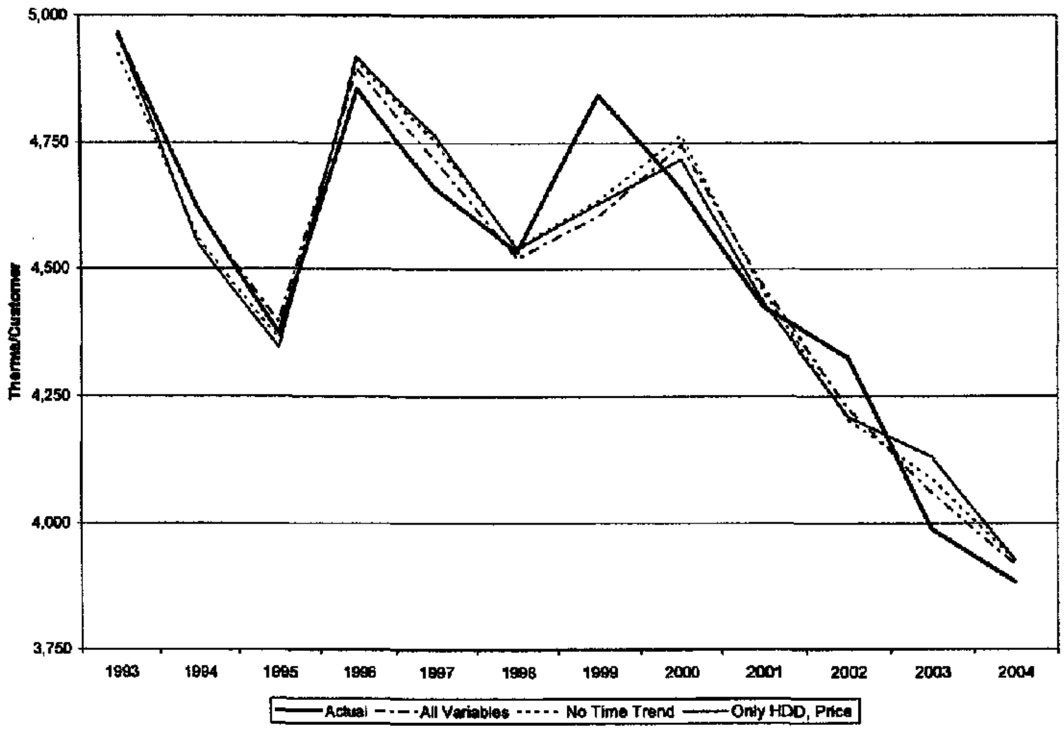


Table 4-4: Breakdown of Change in Use per Customer for Residential and Commercial Classes

Residential	**Use per Customer (therms)**	**HDD**	**Price ($/therm)**
1993 Value	843	3,048	$0.594
2004 Value	673	2,511	$0.969
Change in variable	-170	-537	$0.375
Impact on Use/Cust.	--	-86	-84
% Explained	--	51%	49%
Commercial			
1993	4,963	2,822	$0.524
2004	3,884	2,297	$0.891
Change in variable	-1,079	-525	$0.367
Impact on Use/Cust	--	-514	-526
% Explained	--	48%	49%

The lower portion of the table presents similar results for the commercial class, with differences in weather conditions and an increase in the price explaining a high percentage (97 percent) of the reduction in commercial use per customer.[20] DMN is intended to adjust distribution revenue recovery for non-weather changes in usage per customer (which this analysis indicates consists of price effects and unexplained changes), and WARM adjusts distribution revenue recovery for weather-induced changes in customer usage.

2. Economic conditions, represented by the unemployment rate, did not have a statistically significant effect on residential or commercial use per customer. This is an important result, as it indicates that there is little potential for DMN to shift economic risks from NW Natural to its customers. While the possibility of such a shift exists in theory, the data indicate that the problem is not significant in NW Natural's service territory.

3. The High Efficiency Furnace program did not significantly affect overall average residential use per customer. This result may be explained by NW Natural's estimate that the HEF program produced a 2.4 million therm reduction in total residential usage from 1996 to 2002, which represented only 0.1% of total residential usage over that period. A logical conclusion from this result is that since the HEF program was the most prominent NW Natural conservation initiative during the sample period, NW Natural sponsored conservation was not a major driver of the need for DMN.

4.4 NW Natural Behavior with DMN

The Order approving DMN requires that the independent review address whether DMN affected NW Natural's company culture or operating practices. This will help the Commission to determine whether NW Natural is sincere (and effective) in its efforts to promote conservation. In this section, we address the Commission's requirement by examining NW Natural's marketing efforts, the performance of the residential high-efficiency furnace (HEF) program, a comparison of new connections to existing customers, NW Natural's relevant compensation practices, changes in NW Natural's organizational structure, and third-party views on NW Natural's behavior with DMN. In addition, we interviewed NW Natural employees and third parties (appliance distributors and the NRDC) to provide additional information about changes in NW Natural's culture and business practices.

4.4.1 Marketing Efforts

One way that NW Natural can demonstrate whether it is committed to promoting conservation is through its marketing efforts. We reviewed NW Natural's allocation of marketing resources from 2000 through 2004 in order to evaluate whether a change occurred following the implementation of DMN.

[20] We did not include the other independent variables in this analysis because their estimated coefficients were not statistically significant.

NW Natural allocates its advertising budget to three categories, labeled A, B, and C. They are defined as follows:

Category A: Energy efficiency, conservation, and service information (including rate or account information).
Category B: Safety communication and advertising.
Category C: Promotional advertising and communications to non-customers, or image advertising.

Table 4-5 shows how NW Natural has allocated its Consumer Information budget across these categories from 2000 through 2004. The table shows that resources were shifted away from Category C (promotional and image advertising) and towards Categories A and B beginning in 2001. By 2002, when DMN was approved, the share of Category C had dropped to approximately 20 percent.

Table 4-5: Consumer Information Budget Shares by Category: 2000 through 2004

Year	Category A	Category B	Category C
2000	25%	1%	74%
2001	54%	1%	45%
2002	68%	10%	22%
2003	73%	6%	21%
2004	60%	23%	17%

We also received copies of all marketing materials produced by NW Natural from 2000 through 2004. We reviewed and categorized each print and radio advertisement. Table 4-6 shows the number of advertisements in each category by year. We defined the categories as follows:

- *HEF program*: directly discusses rebates and incentives associated with the residential high-efficiency furnace program;
- *Energy tips*: describes ways that customers can save money by reducing usage;
- *Direct use conservation*: makes the case that direct use of natural gas is an act of conservation;
- *Safety*: warnings about digging or what to do when you smell gas;
- *Load growth*: includes promotions for fireplaces, furnace conversions (primarily from oil), and water heater conversions;
- *Image*: includes general messages (*e.g.*, Black History Month), and messages that provide general support for the use of gas (*e.g.*, clean, efficient, less costly); and
- *Payment options, other regulatory*: includes information about payment options, UNITY, and regulatory notices of changes in rates.

The information provided by this table is limited by the fact that it does not indicate how intensively each item was advertised (*e.g.*, how many times a radio spot was run). However, based only on the number of advertisements, it does appear that NW Natural shifted away from load growth messages (*e.g.*, converting oil furnaces or installing gas fireplaces) and toward promoting high-efficiency furnaces.

Table 4-6: Number of Print and Radio Advertisements by Category and Year: 2000 to 2004

Category	2000	2001	2002	2003	2004
HEF Program	1	10	10	7	4
Energy tips	0	0	0	0	3
Direct use conservation	1	4	5	7	2
Safety	1	3	4	10	11
Load growth	8	2	3	3	1
Image	3	10	9	5	5
Payment options, other regulatory	0	1	2	1	5

There are at least three potential causes for the shift in marketing resources shown in Tables 4-5 and 4-6. First, in UG-132 the Commission clarified its policy with respect to recovery of advertising expenses. Under these rules, image advertising expenses (Category C) carry no presumption of reasonableness. However, expenses in Categories A and B are presumed to be reasonable up to an allowed amount. It is possible that NW Natural shifted its marketing strategy away from image and promotional advertising and toward conservation advertising simply to ensure recovery of the advertising expenses. (In interviews, NW Natural has denied that this was a significant motivating factor in shifting marketing resources.) This explanation is made less plausible by the fact that Category C expenditures comprised a high percentage of the total in 2000, *after* the UG-132 Order was issued in November 1999.

A second potential explanation for the shift away from Category C advertising is that NW Natural was responding to customers who were upset by rapidly increasing prices. That is, by providing information about energy efficiency, NW Natural may have assisted customers in alleviating bill increases caused by rising prices. This can benefit NW Natural by improving the competitiveness of its product (or the *perception* of the competitiveness of the product, to the extent that not everyone is interested in a high-efficiency furnace).

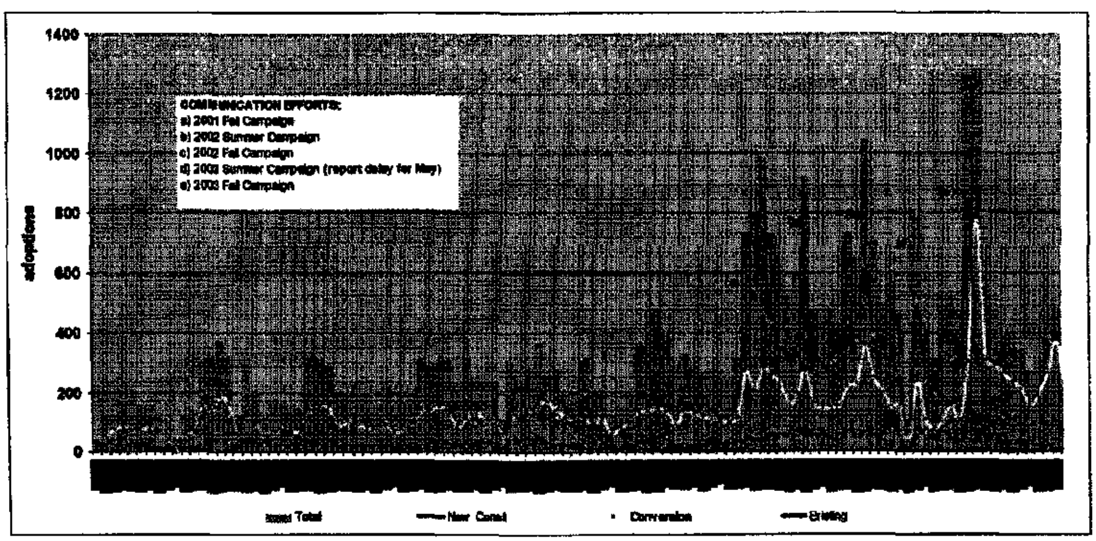
The final potential explanation for the shift away from Category C advertising is that NW Natural responded to the changing incentives provided by DMN. This explanation is made less plausible by the fact that the shift in resources began in 2001 and not in 2002, when DMN was approved by the Commission. However, both CEO Mark Dodson and Kim Heiting, Director of Consumer Information & Internet Services stated in interviews that NW Natural made the decision to behave *as though* they had DMN in 2001. This decision was made in part because it was "the right thing to do" and in part because it helped to address customers' needs in a time of rising prices.

This section demonstrates that NW Natural shifted marketing resources toward promoting conservation beginning in 2001. We do not have enough information to state definitively whether the primary motivation for this shift was a response to a change in the allowed recovery of advertising expenses, a desire to address customer concerns about rising natural gas prices, or a response to a change in incentives provided by DMN.[21]

4.4.2 High-Efficiency Furnace Program Performance

The high-efficiency furnace (HEF) program, which began in 1995, provides residential customers with incentives to adopt high-efficiency furnaces. Prior to DMN, NW Natural was compensated for HEF adoptions through a lost revenue adjustment (called the "Cost Resource Adjustment," in which NW Natural was compensated for lost margins on a case-by-case basis using estimated therm savings). NW Natural changed its approach for managing and promoting this program in October 2001, when it began coordinating more closely with HVAC distributors and packaged rate-funded rebates, distributor-funded rebates, and the Oregon Residential Energy Tax Credit. This approach dramatically increased HEF adoption rates. On October 1, 2003, the administration of the Public Purposes funded rebate program was transferred to the Energy Trust of Oregon. Figure 4-14 below shows monthly HEF adoptions from 1995 through 2004.

Figure 4-14: Monthly HEF Adoptions: 1995 through 2004



[21] Note that NW Natural does not differentiate its marketing in Oregon from its marketing in Washington (except with respect to specific incentives that are only offered in one state), despite the fact that NW Natural has DMN in Oregon, but no equivalent rate mechanism in Washington. In interviews with us, NW Natural stated that the reason for this is that Washington customers represent a small share of NW Natural's total customer base, so it would be more costly to tailor a marketing message to them than it is to endure lost margins from any conservation that is spurred by marketing that is intended for Oregon customers.

Figure 4-14 shows that HEF adoptions increased noticeably when NW Natural modified its approach in October 2001, and that HEF adoptions spike following targeted promotions.

Information from distributors reinforces this evidence of the success of the HEF program. We spoke with Mike Dawson, Northern Regional Manager at Gensco and Glen Bellshaw, Director of Marketing at Airefco. Mr. Dawson provided confidential data comparing the percentage increase in sales of high-efficiency furnaces between 2000 and 2001 (when NW Natural modified the HEF program) in Oregon to Seattle/Tacoma, Eastern Washington, and Montana/Idaho. The percentage increase in HEF sales in Oregon was more than twice the average increase across the other three regions. Mr. Dawson also indicated that according to tracking data from Trane (the primary manufacturer of high-efficiency furnaces sold by Gensco), Oregon has the highest share of HEF sales (as a percentage of total furnace sales) in the nation by a substantial margin. Mr. Dawson attributes this directly to NW Natural's efforts to promote the HEF program.

Mr. Bellshaw provided confidential data comparing the share of high-efficiency furnace sales as a percentage of total furnace sales in Washington and Oregon during 2003 and 2004. His data show that Oregon's share of high-efficiency furnaces is 3.75 times higher than the share in Washington. (The exact percentages by state are confidential.) Mr. Bellshaw attributes this difference to NW Natural's and the Energy Trust's efforts to promote the HEF program. In theory, this comparison could be tainted by the fact that Oregon offers a tax credit for high-efficiency furnaces, while Washington does not. However, Mr. Bellshaw reports that the HEF adoption rates in Cascade Natural and Avista service territories are much closer to the reported Washington share than the Oregon share (which is dominated by NW Natural results). Given this, he concludes that, by itself, the state-level tax credit does not explain the difference in HEF adoption rates between Washington and Oregon.

The increased success of the HEF program began in 2001, prior to the approval of DMN. NW Natural claims that they made a corporate decision to behave as though DMN was in place in 2001, in part because they were looking for ways to help customers who were facing increasing rates. In addition, we note that they were covered by a lost revenue adjustment, which would compensate them for improved program performance (except to the extent that the increased attention given to energy efficiency may have produced more general conservation efforts on the part of consumers).

Finally, we point out that despite the dramatic increase in HEF adoptions, the HEF program has had a modest effect on total residential therms consumed. According to NW Natural estimates, the cumulative HEF adoptions from 1996 through 2004 accounted for approximately a 1% reduction in 2004 residential consumption. The largest single-year effect occurred in 2002, in which 2002 HEF adoptions reduced that year's residential consumption by approximately 0.2%.

4.4.3 Comparison of New Connections to Existing Customers

In approving DMN, the Commission forbade NW Natural from "gaming" the mechanism with respect to new connections. In theory NW Natural could derive short-term gains from DMN by connecting customers whose expected usage is below the baseline use per customer level. This is because NW Natural would receive revenues as though the customer used the baseline levels.

NW Natural provided data that compares existing customers to new connections in 2004, shown in Table 4-7 below. The data are an update of results presented on page AA-3 of NW Natural's 2004 Integrated Resource Plan, and they represent weather normalized annual use per customer for Portland customers.

Table 4-7: Comparison of Existing Customers to New Connections in 2003 (weather normalized annual therms per customer)

Category	Residential		Commercial	
	Annual Use	**Share of Customers**	**Annual Use**	**Share of Customers**
Existing Customers	749	97.9%	4,521	99.0%
New Construction	737	1.5%	7,276	0.6%
Conversions	582	0.6%	3,152	0.5%

The residential results indicate that new connections tend to have lower consumption rates than existing customers. These results should be interpreted with some caution, as factors such as changes in building materials, building codes, and appliance efficiency levels could contribute to the observed differences between existing and new connections customers. The evidence for commercial customers is mixed, with new construction usage rates far exceeding the usage rates of existing customers, but conversion usage rates well below usage rates of existing customers. The large differences in use per customer across the commercial categories is likely due to small sample sizes in the new construction and conversions categories combined with the fact that commercial use per customer can vary considerably depending upon the size of the establishment and nature of the business. (That is, when a small sample is taken from a population with high variance, the mean of the sample is not a very reliable indicator of the population mean.)

In addition to receiving the data shown in Table 4-7, we reviewed the methods that NW Natural uses to assess new connections customers and apply its main extension policy. These methods forecast usage for potential customers based on home characteristics and expected appliance conversions. Using this forecast, the expected profitability of the customers is determined using the standard tariff rates. The revenue effects of DMN are not considered in this calculation.

The data presented in this section present the possibility that NW Natural has discriminated in its new connections in the residential class. However, based on our review of NW Natural's methods for assessing new customer connections, and given the number of other factors that could be affecting the results shown in Table 4-7, it appears to be unlikely that NW Natural has been gaming the DMN mechanism with respect to new connections.

4.4.4 *Cultural and Organizational Effects*

We have already discussed how DMN reduces NW Natural's disincentive to promote energy efficiency. This section addresses whether this incentive change affected NW Natural's compensation practices, organization (*i.e.*, staffing changes), public stance with regards to energy efficiency, or non-regulated business activities.

4.4.4.1 Compensation Practices

This section explores the extent to which NW Natural's compensation practices reveal whether NW Natural is committed to achieving the intended goals of DMN (*i.e.*, shifting away from promoting load growth and toward promoting conservation and energy efficiency, while providing high quality customer service).

Regarding customer service, employees at all levels of NW Natural are eligible for bonuses that are awarded based on several criteria. All employees receive the same percentage bonus. Among the criteria used to determine the level of the bonus is a measure of customer satisfaction.[22] In addition, each member of the management team in Utility Services has individual performance goals and measures related to customer satisfaction. This team includes Kim Heiting (Director of Communication Services), Tamy Linver (General Manager of Consumer Services), Susan Dodge (General Manager of Customer Field Services), Barry Stewart (Manager of Customer Account Services), and Chuck Muehleck (Manager of Customer Billing Services).

NW Natural also has individual employee incentives that are more directly related to DMN. In 2003 and 2004, these incentives were associated with developing and maintaining a relationship with the Energy Trust of Oregon. Employees that were affected by these incentives included Grant Yoshihara (who has overall responsibility of NW Natural's relationship with the Energy Trust), Kim Heiting (who is responsible for integrating Energy Trust messaging with NW Natural's information delivery), and Steve Bicker (who is responsible for contract negotiations and development of policies with the Energy Trust).

Because of an evolution of NW Natural's relationship with the Energy Trust that focused more on "tactical execution," the individual incentives changed somewhat in 2005. Several additional employees were given goals/measures that related to the Energy Trust, including Tamy Linver (who became responsible for the overall Energy Trust working relationship), Tim Abshire (Manager of Program Development), and three program managers responsible for working directly with Energy Trust staff to develop all of NW Natural's residential and commercial programs.

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[22] There is some dispute regarding the effectiveness of group incentives such as this. That is, the incentive for any one person to improve performance is diminished by the fact that the rewards generated from the increase in effort must be shared with everyone, even those who did not exert effort to improve performance).

The goal measurements associated with the incentives described above include a mix of quantitative and qualitative assessments. As an example, NW Natural tracks quantitative measures such as referrals to the Energy Trust, High-Efficiency Furnace adoptions, responses to a specific customer satisfaction survey question on "providing programs and incentives for high efficiency equipment," the number of programs, and the effectiveness of programs. The mix of these measures used for a specific employee depends on the employee's role. Employees with primarily management roles have more qualitative goals associated with building the relationship with the Energy Trust. Measurement of this is typically based on more anecdotal evidence (*i.e.*, receiving positive comments from Energy Trust leadership or Commission Staff).

An additional compensation policy that appears to have been affected by DMN is ending the use of commissions for Consumer Services conversion representatives, which had been used from the mid-nineties into 2004. Grant Yoshihara, NW Natural's Director of Utility Services, had the following comments on this policy:

> When we realized that the commission structure would potentially present the wrong incentives (promote added load), we began evaluating different options. We did not find anything in the traditional incentive pay category that seemed to work, so we moved toward using the performance goals and measures approach that applies to all of our other non-bargaining employees. In order to make this transition, we also needed to complete another major activity - consolidation of the residential and commercial call centers - that impacted the allocation of work between the call center staff and the conversion representatives. We completed this consolidation in the fall of 2004. Given the fact that the incentive compensation system for the conversion representatives had monthly targets and incentives for the calendar year, we decided to wait until the completion of the calendar year before changing the compensation structure for the conversion representatives.

The existence of the compensation practices described in this section indicates that NW Natural has made some efforts to create and maintain a successful relationship with the Energy Trust, and that it recognizes that DMN reduces the incentive to promote load growth.

4.4.4.2 Organizational Changes

In order to learn about how NW Natural's organization may have changed following the implementation of DMN, we submitted the following request to NW Natural: *"Please describe any organizational changes that took place after DMN was in place. These include position additions and subtractions; department expansions, contractions, or reassignments (in terms of reporting structure)."* We received the following response.

> Organizational restructuring and reassignment of work in sales and service functions began in 2002, just prior to the implementation of DMN. The primary objective of this realignment has been to better integrate and leverage resources in

the sales, customer assistance, and customer service areas. The utilization of resources in terms of O&M expense has shifted along with staffing adjustments and resolution of accounting allocations as was agreed to in the 2002 rate case settlement.

Significant organizational changes that have occurred between the beginning of 2002 and present include the consolidation of Customer Account Services Call Center capacity into two locations (initiated in 2001), consolidation of Consumer Services Call Center capacity (customer assistance) into one virtual network (initiated in late 2004), and shifting of Energy Efficiency program resources for transitioning services to the Energy Trust and supporting the Oregon Low Income Energy Efficiency Program (OLIEE) and the Oregon Low Income Gas Assistance Program (OLGA). Smaller adjustments include the consolidation of all research activities (customer service and satisfaction, market and benchmarking), and realignment of sale and service functions from three market segments (residential, commercial, and industrial) to two segments (mass market and major accounts).

During the three-year period from the beginning of 2002 to beginning of 2005, staffing generally declined in sales/marketing areas, and increased in customer assistance and customer service areas as the customer base grew by 10 percent. While some of this was due to adjustments in accounting practices that transferred staff and expense from sales/promotions to customer assistance, a total net reduction in sales/promotion and customer assistance of 17 FTEs occurred. Most recently, the overall management of sales and service activities was consolidated into a new division, Utility Services.

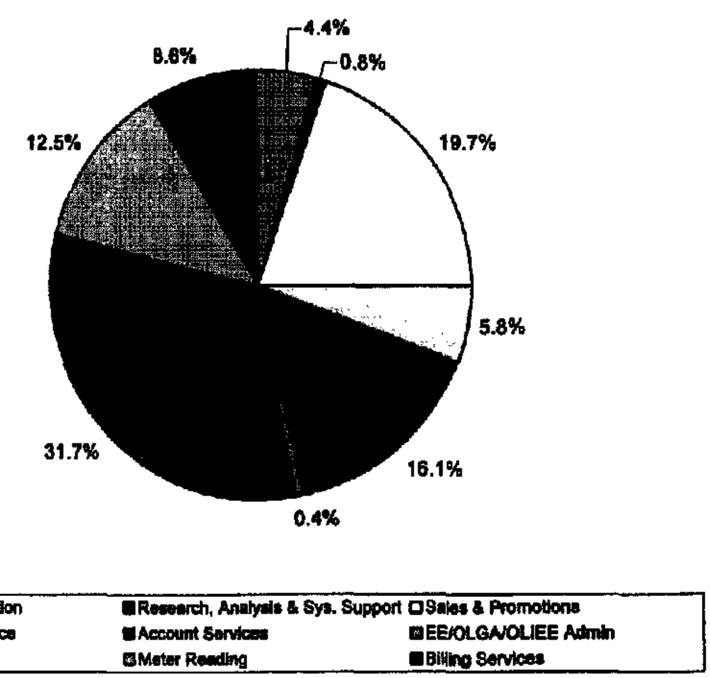
The table shown below identifies the allocation of resources in terms of full time equivalents (FTE's) by functional activity at the beginning of 2002 (actual) and beginning of 2005 (budgeted). A description of the change in staffing is shown for each activity. Also shown below in two charts are the distribution of O&M expense by activity for actual full year 2001 and budget 2005.

Staffing Resource Allocation by Functional Activity
2001 versus 2005

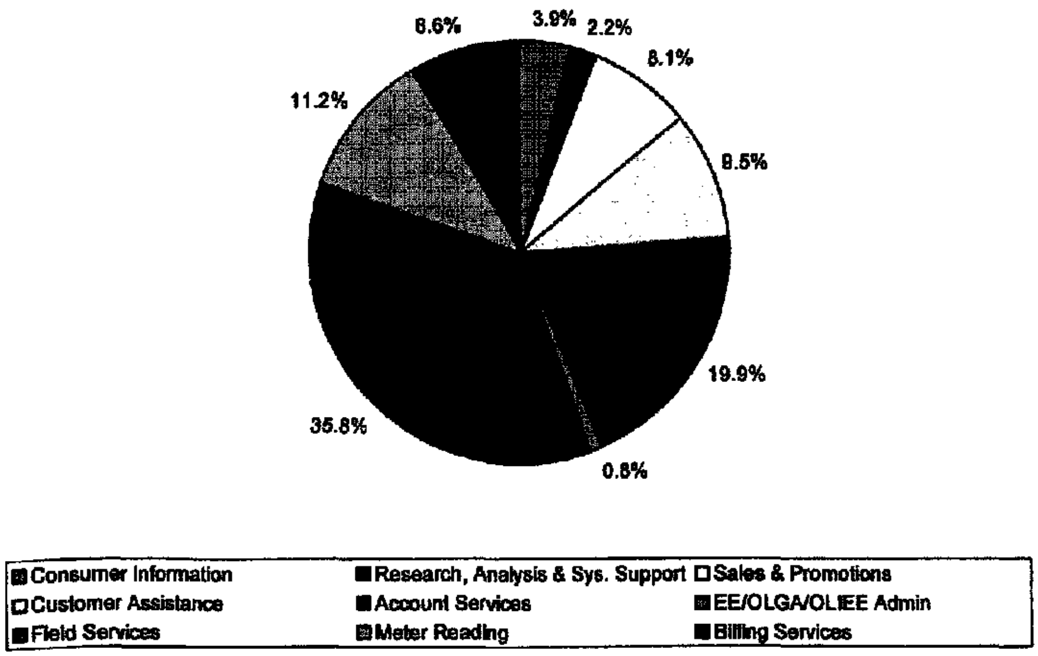
Department or Functional Activity	Description	2002 FTE's	2005 FTE's
Consumer Information & Internet Services	In 2001, staff focus was more concentrated on delivering product benefit and added load communication and advertising designed to help reduce the impact of consumption declines and support conversions. Although the staff level remains consistent, the 2005 work product and funding allocation has moved from a focus on added load and image advertising to a message concentration on energy efficiency, service and safety education.	1.5	1.5
Research, Analysis, & Systems Support	Research efforts were centralized and expanded to include a dedicated customer satisfaction analyst. Additional staffing was added to provide systems support and market analysis.	3.0	6.5
Sales and Promotions	Marketing, sales, and promotions staffing was reduced and reassigned following the 2002 rate case settlement. Accounting adjustments based on time tracking studies submitted as part of the rate case supported some reallocation of expense between sales/promotions and customer assistance. Program development activities for development of existing customer service programs were added in 2004.	67	20.5
Customer Assistance (Acquisition)	Customer assistance staffing (performing functions related to customer acquisition) were consolidated into two market segments for improved efficiency. Portland call centers were consolidated to provide first call resolution service for serving new customers.	18	44
Customer Account Services	Increased staffing is primarily attributable to call center staffing additions to meet increased customer call volumes related to customer growth and higher retail gas prices, consistent with approvals received in the 2002 rate case.	93	113
Energy Efficiency, Oregon Low Income Energy Efficiency, and Oregon Low Income Gas Assistance	Programs added as part of DMN and Public Purpose Funding settlement. Only administrative expenses are shown in the O&M expense distribution charts.	2	3

Department or Functional Activity	Description	2002 FTE's	2005 FTE's
Customer Field Services	Staffing increases to support field service activities has been primarily to handle growth in the customer base. Higher volumes of credit/non-payment customer calls due to higher gas prices has been absorbed through efficiency improvements.	145.5	151
Meter Reading	Despite significant customer growth, a decline in meter reading staffing requirements has resulted from improved route design and adjustments, and improvements in PGE-NWN joint meter reading performance.	74.5	71.5
Customer Billing Services	Staffing increases to support billing activities have been primarily to handle increased bill volume, more complex billing arrangements, and meet Sarbanes Oxley requirements. Mass market and major account billing activities were also consolidated for management and oversight purposes.	13	18.5

2001 Cost Distribution



2005 Cost Distribution



[End of NW Natural's response to CAEC's request. Note that the 2001 and 2005 cost distribution figures are most easily interpreted when viewed in color.]

The most notable changes between 2002 and 2005 are the reduction in full-time employees (FTEs) in sales and promotions, and the increase in FTEs in customer assistance and customer account services. According to Grant Yoshihara, NW Natural's Director of Utility Services, approximately 50% of this shift was an accounting shift based on the results of a time tracking study. (That is, the shift in resources was made to reflect the how time was already being spent by employees.) The remaining 50% of the shift in resources represented a change in focus away from sales and promotions and toward customer service. According to Mr. Yoshihara, this reallocation was part of a larger effort to get sales personnel to coordinate more closely with service personnel.

4.4.4.3 Nexus Home Analyzer

Recently, NW Natural paid approximately $250,000 to install the Nexus Home Analyzer on its website. It allows residential customers to answer a few simple questions about their home (*e.g.*, the number of rooms, the fuel used for space heating, etc.) and then provides information about the sources of energy usage and ways that customers can conserve energy. By raising awareness about how customers use energy, this is an effective tool in promoting general conservation. In the absence of the incentives provided by DMN, NW Natural would not likely have offered this service to its customers.

4.4.4.4 Public Stance on Energy Efficiency

There are several ways in which NW Natural has taken steps to publicly support energy efficiency and conservation. CEO Mark Dodson and others at NW Natural have presented their experiences under DMN, including the benefits of conservation and energy efficiency, at a number of conferences and forums. Mr. Dodson was quoted in a February 2005 *American Gas* article titled "It's Now Easier Being Green: Some natural gas utilities are working to separate their financial health and energy sales" as saying: "We think we have an obligation. Not only a moral obligation to conserve energy, but also a more basic obligation to each customer to try to keep their bills as low as possible." Further reinforcing his public stance in favor of conservation, Mr. Dodson serves as the co-chair of the Governor's Advisory Group on Global Warming in Oregon. The Oregon Department of Energy website lists the objective of this group as follows:

> The purpose of the advisory group is to develop a strategy to reduce Oregon's greenhouse gas emissions both in the short term and over the long term. The strategy will be coordinated with the West Coast Governors' Global Warming Initiative. The Governor requested the strategy by September 2004.
>
> The climate change strategy for Oregon will provide long-term sustainability for the environment, protect public health, consider social equity, create economic opportunity, and expand public awareness. The Advisory Group will make recommendations to Governor Kulongosk.

Based on actions such as these, Ralph Cavanagh of the NRDC called NW Natural the top energy efficiency advocate in the industry. In our interview with him, Mr. Dodson pointed out the difficulty that he would face should DMN be taken away. On the one hand, he has taken a public stance supporting the benefits of conservation. However, in the absence of some form of decoupling, NW Natural shareholders would be harmed by conservation. Mr. Dodson used this example to indicate the harm that can be caused by what he referred to as inconsistent regulation.

4.4.4.5 Non-Regulated Business Activities

According to NW Natural CFO David Anderson, non-regulated activities account for only about 3% of assets, and the risk reductions afforded by DMN and WARM did not affect non-regulated activities. Changes in non-regulated revenues in recent years are primarily related to the proposed (and abandoned) merger with PGE and Mist natural gas storage.

4.4.5 Third Party Views on NW Natural Behavior with DMN

We spoke with four people in order to get a different perspective on NW Natural's actions with DMN:

- Ralph Cavanagh of the Natural Resources Defense Council (NRDC);
- Margie Harris, Executive Director of the Energy Trust of Oregon;
- Mike Dawson, Northern Regional Manager of Gensco;

- Glen Bellshaw, Director of Marketing at Airefco;
- Bob Jenks, Executive Director of the Citizens' Utility Board;

The input that we received from these individuals consistently indicated that NW Natural is sincere in its commitment to promote conservation efforts, specifically in the form of high-efficiency furnaces. Mr. Cavanagh believes that through public presentations by CEO Mark Dodson,[23] NW Natural has demonstrated that it is the leading advocate of energy efficiency in the industry. Mr. Cavanagh reported to us that "I have never seen this level of public enthusiasm by a utility CEO on the conservation benefits of decoupling or the importance of expanded involvement in energy efficiency by natural gas utilities (at NW Natural or anywhere else)."

Ms. Harris described the Energy Trust's current relationship with NW Natural in very positive terms. She acknowledged that there were initial difficulties in forming a working relationship with NW Natural, in particular in the area of data transfers, which produced problems that took about one year to resolve. However, at this point Ms. Harris notes that NW Natural:

- is very responsive to the Energy Trust,
- has increased the number of "touch points" (*i.e.*, individuals that work with the Energy Trust), and
- has regular meetings with the Energy Trust.

In addition, as a customer of NW Natural's she has also noticed an increase in the inclusions of a conservation message in collateral advertising and bill inserts.

There are a couple of areas in which Ms. Harris believes that NW Natural could improve. First, she would like to see NW Natural be consistent in including the Energy Trust in its conservation-based messaging. This would reinforce the partnership that NW Natural and the Energy Trust have formed. Second, she believes that NW Natural could do a better job of diversifying its conservation efforts beyond the residential class. (While NW Natural and the Energy Trust have recently initiated a commercial energy efficiency program, Ms. Harris believes that programs could be expanded to industrial customers as well. However, doing so could present NW Natural with a financial concern, as DMN does not cover industrial customers.)

Section 4.4.2 above contains the information provided by Mr. Dawson and Mr. Bellshaw that indicates that NW Natural's efforts have increased HEF adoptions. Mr. Bellshaw said that NW Natural has changed its attitude about how they do business with contractors, creating a more open process. Mr. Dawson echoed this point, saying that NW Natural is more active in dealing directly with distributors, and that NW Natural has been effective in providing "warm" sales leads to his company.

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[23] Some examples of public presentations are: joint presentations by Mr. Dodson and Mr. Cavanagh to the National Association of Regulatory Utility Commissioners and to a joint workshop of the Washington and Oregon Commissions; and Mr. Dodson's keynote address at Bonneville Power Association's Fall 2004 Regional Energy Efficiency conference.

No one among Mr. Cavanagh, Ms. Harris, Mr. Dawson, and Mr. Bellshaw believed that there were any negative aspects of DMN with respect to its effect on NW Natural's actions, though Mr. Cavanagh commented that DMN could be improved by adopting NW Natural's original proposal for full decoupling, which Mr. Cavanagh believes would be less complex and more effective.

Bob Jenks, the Executive Director of the Citizens' Utility Board of Oregon, believes that DMN has been good for consumers. He provided the caveat that his support for DMN is due to the Public Purposes Funding rather than the incentives provided by DMN. That is, he has seen decoupling implemented in the past (for PGE and PacifiCorp) without a change in corporate commitment to conservation. The funding provided by the Public Purposes charges provides tangible support for energy efficiency programs and bill payment assistance. Aside from that caveat about decoupling, Mr. Jenks believes that NW Natural has been supportive and helpful to the Energy Trust in promoting energy efficiency programs.

Taken together, we believe that the views expressed to us indicate that NW Natural takes its commitment to promoting energy efficiency seriously. Mr. Cavanagh's statements show the extent to which NW Natural has linked its corporate image with energy efficiency through public presentations. Ms. Harris, representing an organization dedicated to promoting energy efficiency, believes that NW Natural has made significant efforts to work with her organization to further its goals. Finally, two representatives from appliance distributors provide a front-line account of the effect that NW Natural's (and, since October 2003, the Energy Trust's) efforts have had on high-efficiency furnace sales.

4.5 Financial Data

The Commission Staff requested that we provide information regarding financial effects of DMN on NW Natural. The Commission agreed with us that it would be difficult to attribute changes in financial outcomes specifically to DMN (given the large number of other factors that can affect stock prices, interest rates, etc.). Therefore, this section primarily contains data for various financial indicators over time (lines of credit, bond ratings, stock prices, etc.), but it does not include any formal analyses that attempt to assign changes in financial indicators to DMN or other potential causal factors.

4.5.1 Lines of Credit

NW Natural secures lines of credit in order to protect itself against variations in cash flow. This section describes how the terms of the lines of credit have changed from October 1998 through September 2004. Table 4-8 shows how the lines of credit have changed each year, including the total dollar amount of the credit lines and the average fees associated with them.

Table 4-8: NW Natural Lines of Credit: October 1998 through September 2004

Date	Total Amount of Credit Lines ($ millions)	Basis Point Fees
10/1998 to 9/1999	$100	8.18
10/1999 to 9/2000	$120	8.38
10/2000 to 9/2001	$120	7.50
10/2001 to 9/2002	$150	8.40
10/2002 to 9/2003	$150	10.63
10/2003 to 9/2004	$150	9.50

Beginning in October 2002, NW Natural began securing half of its credit line for a two-year commitment, and the other half for a one-year commitment. Prior to this date, all of its credit line was secured for one-year. Because two-year lines of credit are more costly, an increase in the basis point fees occurred at this time. According to David Anderson, NW Natural's current CFO, this change in strategy reflects an increase in NW Natural's risk management sophistication, bringing them in line with industry best practices. He reported that the change was not related to DMN.

4.5.2 Bond Ratings and Bond Issuances

There has been only one change in NW Natural's bond rating since 1995, which was an increase in the S&P bond rating from A to A+ in 2004. NW Natural has issued 15 long-term bonds since 1999. Table 4-9 below shows the year the bond was issued, the year the bond is due, and the interest rate paid by the bond.

Table 4-9: NW Natural Bond Issuances: 1999 through 2004

Year Issued	Year of Maturity	Interest Rate
1999	2001	6.62%
1999	2002	6.75%
1999	2019	7.63%
2000	2030	7.74%
2000	2025	7.72%
2000	2030	7.85%
2000	2010	7.45%
2001	2006	6.05%
2001	2011	6.665%
2002	2007	6.31%
2002	2012	7.13%
2003	2032	5.82%
2003	2033	5.66%
2004	2010	4.11%
2004	2023	5.62%

According to CFO David Anderson the presence of DMN and WARM contributed to NW Natural attaining a score of "1" on S&P's business risk profile (in which 1 = best risk profile and 10 = worst risk profile). This rating has two effects. First, it allows NW Natural the flexibility to carry a lower share of equity in its capital structure if it chooses. Second, a favorable business risk profile rating allows NW Natural the flexibility to maintain a lower debt-service coverage ratio if it chooses.

4.5.3 Stock Offerings

Table 4-10 shows the dollar amounts associated with stock offerings and repurchases from 1993 through 2004. These data are taken from NW Natural's annual 10-K filings to the SEC in the "financing activities" section of the consolidated statement of cash flows. Note that we have pooled redeemable preferred stock and redeemable preference stock retired in the "Preferred Stock Retired" column.

Table 4-10: NW Natural Stock Issues and Repurchases: 1993 to 2004 ($000)

Year	Common Stock Issued	Common Stock Repurchased	Preferred Stock Retired
1993	$5,720	$0	$11,177
1994	$5,847	$0	$1,091
1995	$39,569	$0	$1,163
1996	$5,690	$0	$1,091
1997	$6,465	$0	$1,320
1998	$52,384	$0	$930
1999	$5,356	$0	$935
2000	$4,826	$2,441	$814
2001	$5,157	$5,792	$750
2002	$6,872	$0	$25,750
2003	$8,349	$0	$8,428
2004	$48,153	$0	$0

4.5.4 Comparison of NW Natural Stock Prices to an Index of Utilities

All else equal, markets place a higher value on companies that have more stable profits. DMN has this effect in theory, as it reduces the variability of fixed cost recovery. Presumably because of this, the Commission expressed an interest in comparing NW Natural's stock price to an index based on a representative sample of utilities. The sample used here corresponds to the sample that was used to determine return on equity (ROE) in NW Natural's last rate case (UG-152). It consists of the following utilities (the stock ticker symbol is in parentheses):

1. AGL Resources (ATG)
2. Atmos Energy (ATO)
3. Cascade Natural Gas (CGC)
4. Energen (EGN)

5. Laclede Gas (LG)
6. Nicor (GAS)
7. NW Natural Gas (NWN)
8. Peoples Energy (PGL)
9. Piedmont Natural Gas (PNY)
10. SEMCO Energy (SEN)
11. Southwest Gas (SWX)
12. WGL Holdings (WGL)

Data were collected from Yahoo! Finance, which publishes historical monthly stock prices adjusted for dividends and splits. The stock price index was calculated as the average (unweighted) stock prices of the utilities in the sample (excluding NW Natural). Figure 4-15 shows the adjusted monthly stock prices for NW Natural and the index of utilities from January 1993 through January 2005. The two series track one another quite closely, which is surprising given that the stock prices of the utilities comprising the index vary substantially. Figure 4-16 shows the adjusted stock prices for all twelve utilities, with NW Natural's data in bold. (This figure must be viewed in color to be able to identify the individual utilities. The figure's legend identifies the data using each company's stock ticker symbol.)

Figure 4-15 shows that NW Natural's stock price increased relative to the index around the time that DMN was approved (in August 2002). Shortly thereafter, NW Natural's stock price reverted to a level closer to the index. During 2003 and early 2004, NW Natural's stock price once again increased relative to the index. This gain was largely maintained through January 2005.

These figures simply show the stock prices for NW Natural and a set of comparable utilities. A number of factors could have affected stock prices over this time period, and because of this we do not claim to provide explanations for changes in the stock prices over time. However, it does appear that NW Natural's stock price increased relative to the index around the times that DMN and WARM were approved.

Figure 4-15: Monthly Stock Prices for NW Natural and an Index of Utilities

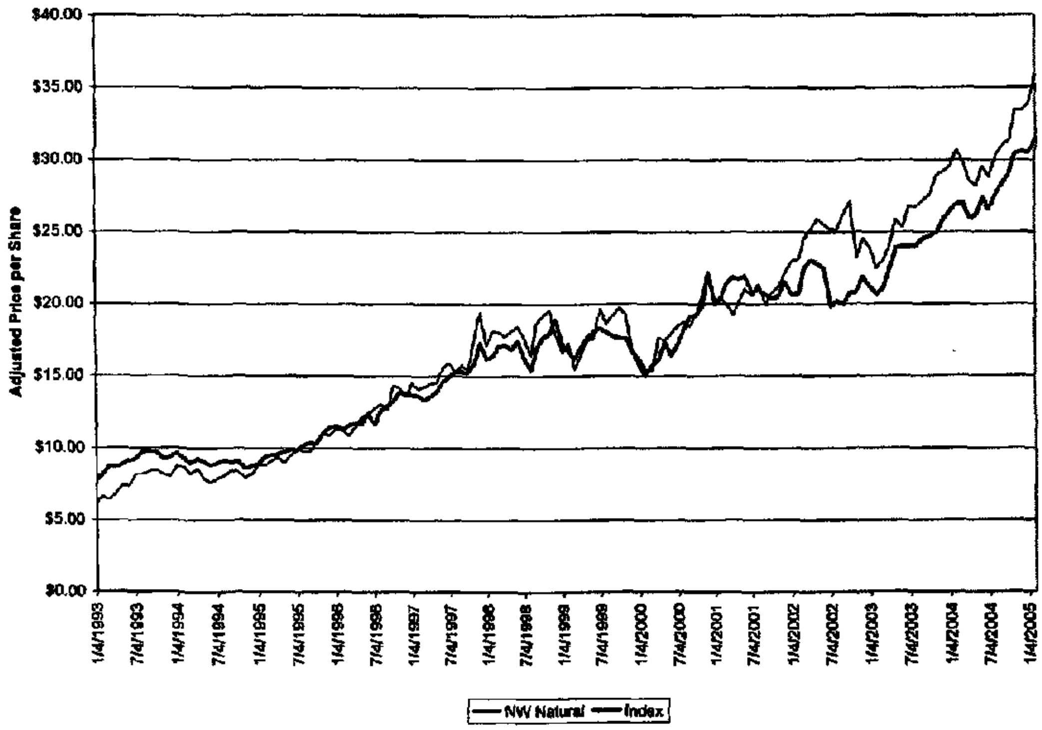
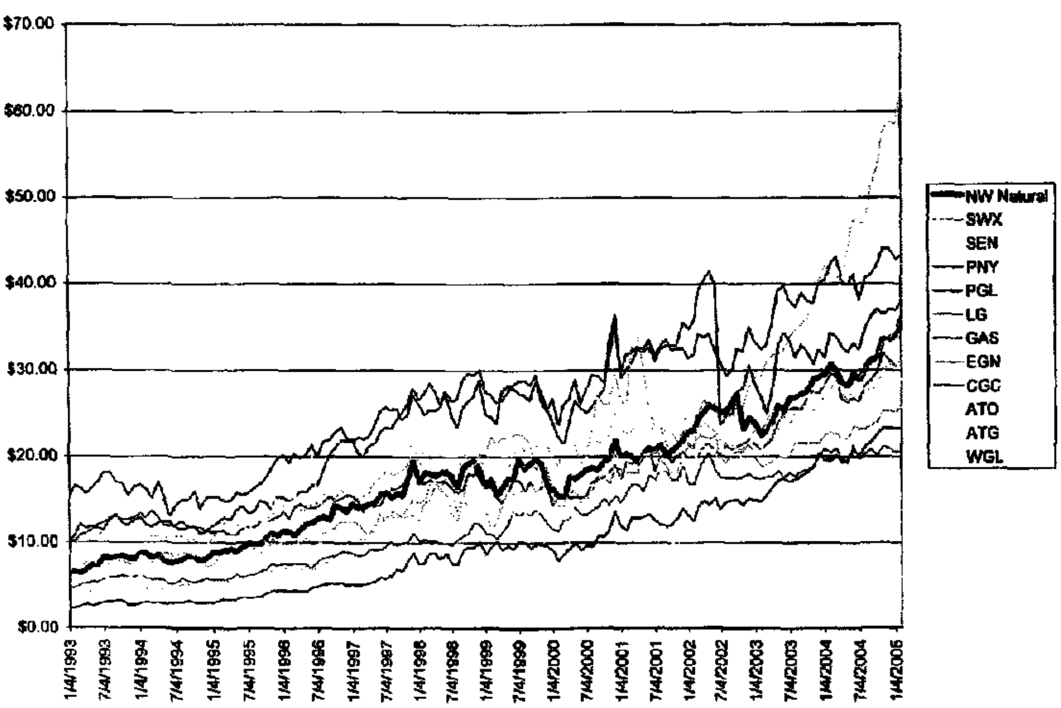


Figure 4-16: Monthly Stock Prices for Twelve Natural Gas Utilities



4.5.5 Reports to Rating Agencies

Commission Staff suggested that we examine NW Natural's reports to rating agencies to see how NW Natural portrays the benefits of DMN and WARM. These reports tend to contain the following elements:

- Tables of financial data;
- Bullet points containing financial highlights (not present prior to 2001); and
- The SEC 10-K annual filing.

To get an idea of how these reports treat DMN and WARM, it is useful to compare the financial highlights from 2003 to those of 2001. The following bulleted text is reproduced from NW Natural reports to rating agencies.

2003 Financial Highlights

- Earnings of $1.76 a share, vs. $1.62 a share in 2002
  - Oregon general rate case contributed $0.09 a share in additional revenues
  - Earnings of $0.17 a share from Gas Storage, vs. $0.14 in 2002
  - Earnings of $0.08 a share from Oregon decoupling mechanism, $0.05 a share from WARM, vs. $0.04 a share from decoupling in 2002
  - Earnings of $0.12 a share from gas commodity savings and off-system sales, vs. $0.28 in 2002
  - Electric generation market contributed no earnings in 2003, vs. $0.11 a share in 2002
  - Higher earnings for pension, health benefits and insurance reduced earnings in 2003 by $0.12 a share
  - Results in 2002 included charges equivalent to $0.33 a share for PGE transaction costs written off
- Cash from operations (before working capital changes) of $102 million, vs. $121 million in 2002
- Utility investments of $125 million, vs. $80 million in 2002
- Net increase in long-term debt of $35 million, vs. $49.5 million in 2002
- Net decrease in preferred and preference stock of $8 million, vs. decrease of $26 million in 2002

2001 Financial Highlights

- Diluted EPS from continuing operations of $1.88 a share compared to $1.79 in 2000
- Weather 3 percent colder than average, but 2 percent warmer than 2000; depressed consumption per degree day reduced earnings by $0.26 a share
- Margin revenues up 5 percent despite depressed consumption patterns
- Storage services added $0.08 a share to earnings
- Electric generation provided $0.11 a share
- Gas commodity savings provided $0.11 a share

These financial highlights show that the presence of DMN and WARM is included, along with their effects in terms of earnings per share. However, DMN and WARM do not appear to receive an unusual amount of attention in the reports. For example, in the 2003 Financial Highlights, the Oregon rate case is listed before DMN or WARM, and its effects on earnings per share are higher.

4.6 Service Quality Issues

4.6.1 Data on Frequency and Nature of Complaints

NW Natural did not report any customer complaints directed specifically at the DMN mechanism. This is likely because rate adjustments caused by DMN are not separately listed on customer's bills. NW Natural reported that there were some complaints generated by the Public Purposes Funding, but they did not provide details.

The Commission provided the "verbatim" complaints (text of letters, e-mails, or transcriptions of telephone calls) associated with UG-143. Twenty-six such complaints were lodged with the Commission between September 2002 and January 2003. The nature of the complaints was uniform, with customers questioning the appropriateness and/or legality of imposing Public Purposes Funding charges on their bills. The complaints were based on the customer's belief that the Public Purposes Funding is taxation without representation, a socialist/communist redistribution of income, and/or forced charitable giving. None of the complaints specifically mention rate adjustments due to the DMN mechanism. (Again, we would not expect them to, as the adjustments are not separately listed on bills.) These negative comments are counter-balanced by the positive comments that we received regarding the value of the funding from the Citizens' Utility Board and community action and planning (CAP) agencies, which indicated the high value of OLIEE and OLGA funding generated by the Public Purposes charges to their organizations.[24] We do not attempt to evaluate the relative importance of the twenty-six complaints (which Deborah Garcia of Commission Staff regards as a significant number of complaints relative to the number of complaints received on other issues) and the benefits derived by the recipients of OLGA and OLIEE funds.

4.6.2 Frequency and Duration of Outages

The Commission Staff raised the possibility that DMN could reduce NW Natural's incentive to address customer outages. That is, if a customer service outage occurs, the DMN deferral mechanism will compensate NW Natural for any lost margins due to a reduction in sales. We requested that NW Natural provide information on the frequency and duration of outages before and after DMN. We received the following response:

> The requested information is unavailable. It is exceptionally rare for NW Natural to experience service interruptions to its customers. In the

[24] The CAP agency representatives that indicated the high value of the Public Purposes funding were: Judy Schilling, Energy & Emergency Assistance Coordinator for Washington County; Karrie Durie of the Community Action Team; Jacque Meier, Weatherization Manager for Clackamas County; Terry Weygandt of the Community Services Consortium; Margaret Davis of the Mid Columbia Community Action Council; and Joan Ellen Jones, Weatherization Manager for Washington County.

highly unlikely event of a service outage, NW Natural has an Incident Command System (ICS) in place to provide a coordinated response ensuring public safety and restoration of service at the earliest possible moment. In almost every circumstance, NW Natural is able to restore service the same day, if not sooner.

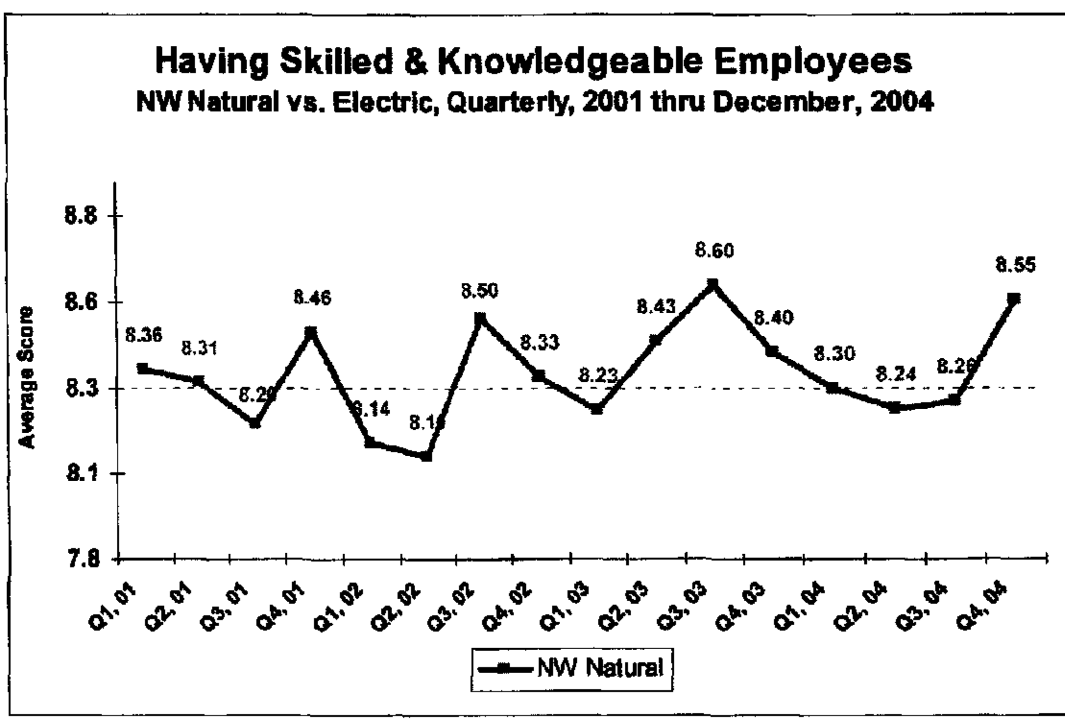
While we do not have direct data to verify the fact that service interruptions have not changed with the introduction of DMN, the customer service ratings data described in the next section indicates that it is unlikely that a problem has arisen in this area. In addition, it is intuitively implausible to us that the small financial incentive associated with delaying repair of an outage would outweigh the customer service costs and the risk of litigation from allowing unsafe circumstances to persist.

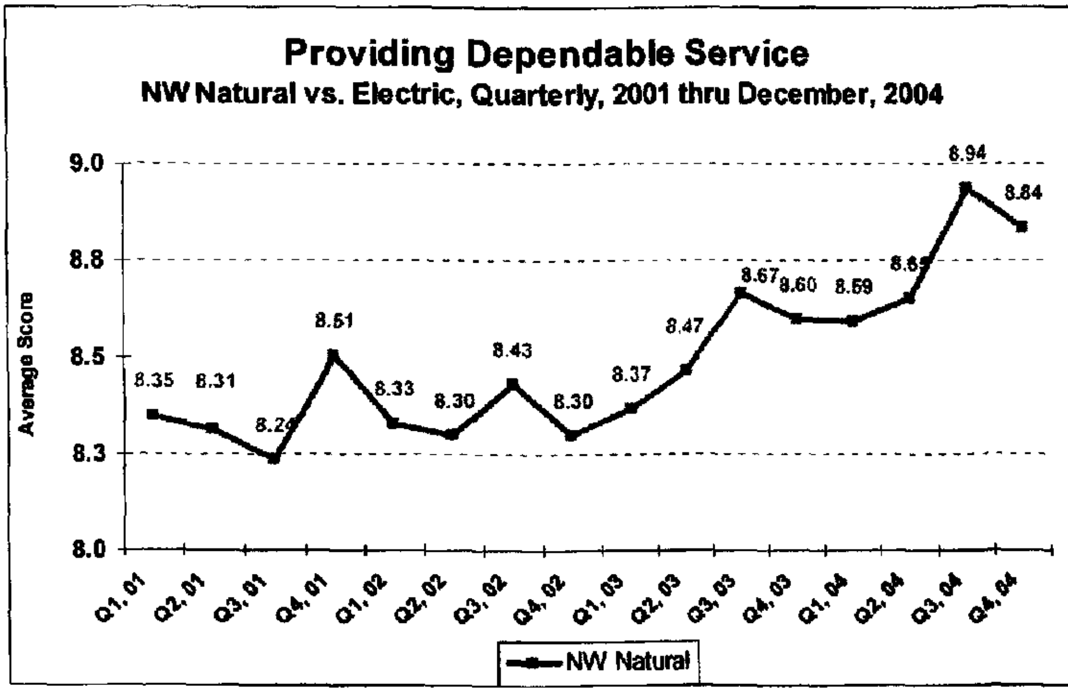
4.6.3 Customer Service Ratings

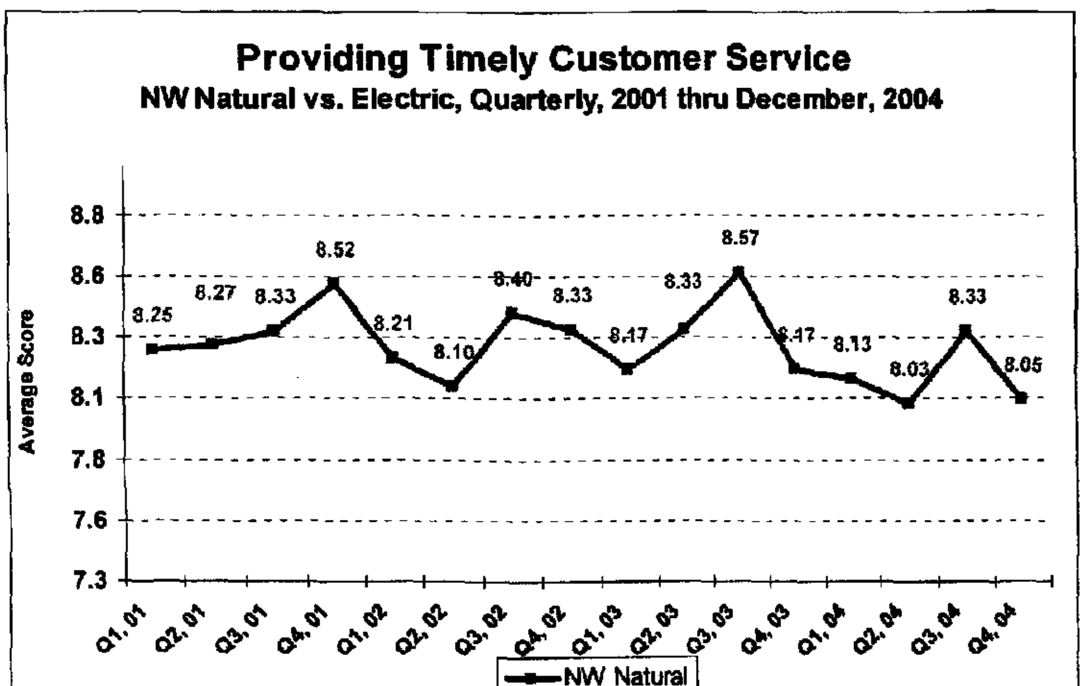
NW Natural conducts a monthly survey of customer satisfaction, with the sample consisting of customers that have contacted the company. Customers are asked to rate NW Natural in three areas on a scale from one (poor) through ten (excellent). The questions are as follows: *How well does your gas utility perform on...*

1. *Having skilled and knowledgeable employees.*
2. *Providing dependable service.*
3. *Providing timely customer service.*

The three figures below show NW Natural's ratings for each of these areas from 2001 through 2004.




Providing Dependable Service
NW Natural vs. Electric, Quarterly, 2001 thru December, 2004
Average Score
9.0
8.8
8.5
8.3
8.0
8.35
8.31
8.24
8.51
8.33
8.30
8.43
8.30
8.37
8.47
8.67
8.60
8.59
8.94
8.84
Q1, 01
Q2, 01
Q3, 01
Q4, 01
Q1, 02
Q2, 02
Q3, 02
Q4, 02
Q1, 03
Q2, 03
Q3, 03
Q4, 03
Q1, 04
Q2, 04
Q3, 04
Q4, 04
NW Natural


Providing Timely Customer Service
NW Natural vs. Electric, Quarterly, 2001 thru December, 2004
Average Score
8.8
8.6
8.3
8.1
7.8
7.6
7.3
8.25
8.27
8.33
8.52
8.21
8.10
8.40
8.33
8.17
8.33
8.57
8.17
8.13
8.03
8.33
8.05
Q1, 01
Q2, 01
Q3, 01
Q4, 01
Q1, 02
Q2, 02
Q3, 02
Q4, 02
Q1, 03
Q2, 03
Q3, 03
Q4, 03
Q1, 04
Q2, 04
Q3, 04
Q4, 04
NW Natural

Since 2001, the "skilled employee" and "dependable service" ratings have increased, while the "timely service" rating has declined. However, note that the scale used in these figures is somewhat "tight," so that only the increases in the "dependable service" rating seems to represent a significant change since DMN went into effect in the fourth quarter of 2002.

NW Natural has recently subscribed to the J.D. Power and Associates Customer Satisfaction Survey. This information is confidential, and therefore we will only describe the qualitative results for NW Natural with respect to responses to two questions and two indexes, which are compiled across a number of questions. The questions for which we describe the results are as follows.

1. *How would you rate the ability of your natural gas utility to help you reduce your monthly bill? Scale is from one (unacceptable) to ten (outstanding).*
2. *How familiar are you with education or rebate programs from your local natural gas utility to help you with ways to use less gas? Scale is from one (not at all familiar) to ten (very familiar).*

Regarding the first question, NW Natural was ranked 26th out of 55 companies in 2003. In 2004, this ranking improved to 14th out of 55 companies. For the second question, NW Natural ranked 6th out of 55 companies in both 2003 and 2004.

J.D. Power and Associates produces two indexes of interest: an Overall Customer Satisfaction Index and a Customer Service Index.

The Overall Customer Satisfaction Index includes the following factors:

- Price and value
- Company image
- Field service
- Customer service
- Billing and payment

Using this index, NW Natural was ranked 10th out of 55 in 2003 and 9th out of 55 in 2004.

The Customer Service Index includes the following factors:

- Courteous and friendly employees
- Answering questions first time final
- Length of time to answer questions/resolve problem
- Promptness in speaking to CSR
- Employees having sufficient knowledge

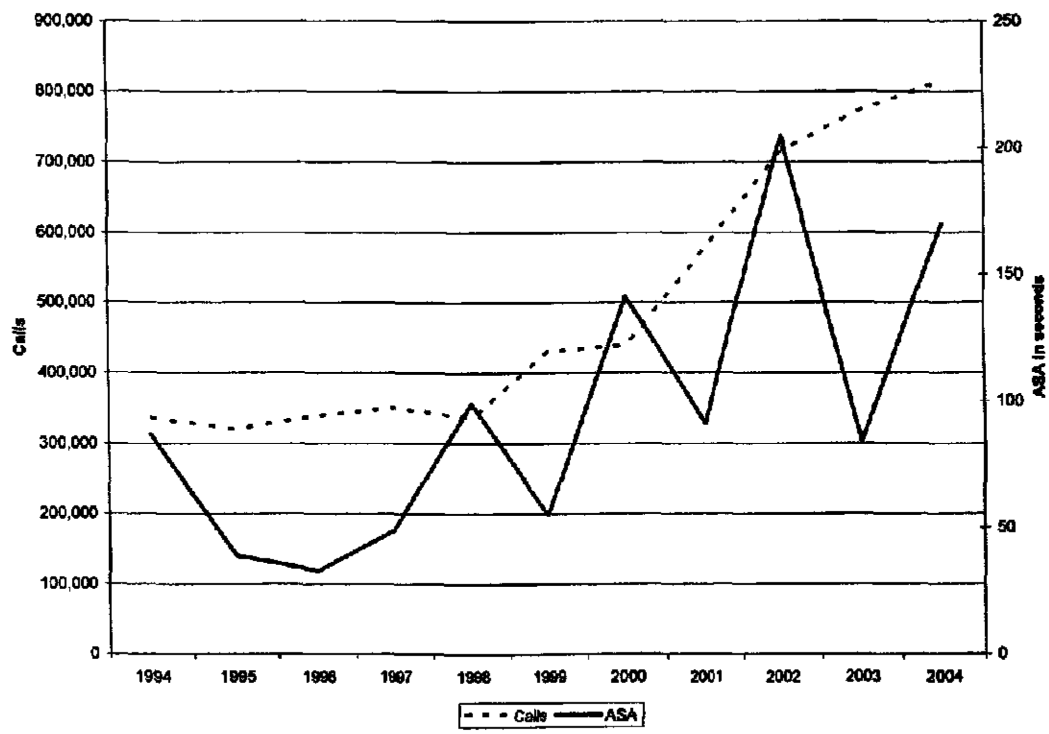
Using this index, NW Natural was ranked 4th out of 55 in 2003 and 5th out of 55 in 2004.

The information presented in this section indicates that NW Natural has not allowed its level of customer service to decline since DMN was implemented. According to both internal and national surveys, it appears that the level of customer service provided by NW Natural is very good overall.

4.6.4 Call Center Performance Data

In order to provide another measure of customer service quality, we obtained data on NW Natural call center volumes and average speed of answer (ASA, or the number of seconds that it takes for a caller to receive service) from 1994 through 2004. Figure 4-17 below displays this information.

Figure 4-17: Annual Call Center Volumes and Average Speed of Answer in Seconds: 1994 through 2004



This figure shows that ASA tends to follow call volumes. That is, as call volumes increase (in part because of price increases), it takes longer for a caller to speak to a customer service representative. The decrease that occurs in 2003 and 2004 is likely due to the fact that the Commission approved an increase in the number of NW Natural customer service personnel. We do not see a reason to directly attribute this change to DMN. Overall, we interpret this figure as showing that DMN did not negatively affect call center performance.

4.7 Uncollectible Accounts

As noted in Section 2 above, we do not believe that DMN affects NW Natural's incentives to pursue uncollectible accounts. That is, the DMN deferrals are calculated using (weather-adjusted) sendout volumes, the actual number of customers, and a pre-established margin per therm. Revenues that are not collected from customers do not flow back into the DMN deferrals.

Nevertheless, the Commission Staff expressed a desire to see data regarding uncollectible revenues before and after DMN was approved. Tables 4-11 and 4-12 contain NW Natural's annual uncollectible accruals and write-offs, respectively. Uncollectible revenues tend to increase as rates increase. The best example of this is seen in the change in residential uncollectible revenues between 2000 and 2001, in which a 20 percent increase in prices led to a 32 percent increase in uncollectible revenues. The effect of higher prices seems to stabilize, however, as uncollectible revenues decreased in 2002 and 2003 despite the presence of slightly higher prices than in 2001.

Table 4-11 provides evidence that DMN does not affect NW Natural's incentives to pursue uncollectible accounts, as uncollectible write-offs declined dramatically from 2002 to 2003, a period in which DMN was in effect.

Table 4-11: Annual Uncollectible Accrual by Rate Class

	Residential			Commercial		
Year	Uncollectible Revenue	Percent Change	Avg. Rev.	Uncollectible Revenue	Percent Change	Avg. Rev.
1999	$1,997,062		68.8	$278,718		55.2
2000	$1,873,153	-6.2%	78.7	$428,010	53.6%	63.8
2001	$2,477,666	32.3%	94.2	$377,925	-11.7%	78.5
2002	$2,098,109	-15.3%	99.3	$411,942	9.0%	83.9
2003	$1,381,340	-34.2%	95.6	$297,173	-27.9%	78.0
2004	$2,684,187	94.3%		$396,493	33.4%	

Table 4-12: Annual Uncollectible Net Write-offs by Rate Class

	Residential			Commercial		
Year	Uncollectible Revenue	Percent Change	Avg. Rev.	Uncollectible Revenue	Percent Change	Avg. Rev.
1999	$1,946,308		68.8	$280,529		55.2
2000	$1,509,603	-22.4%	78.7	$433,056	54.4%	63.8
2001	$2,268,892	50.3%	94.2	$389,204	-10.1%	78.5
2002	$2,369,467	4.4%	99.3	$428,877	10.2%	83.9
2003	$1,582,589	-33.2%	95.6	$296,442	-30.9%	78.0
2004	$2,139,123	35.2%		$376,229	26.9%	

4.8 OLGA and OLIEE

As part of Order 02-634 establishing DMN, the Commission approved Public Purposes Funding to support the Oregon Low-Income Energy Efficiency Program (OLIEE), the Oregon Low-Income Gas Assistance Program (OLGA), and enhanced energy efficiency programs. Section 4.4.2 discusses the performance of the most prominent enhanced energy efficiency program, the residential HEF program. This section discusses OLIEE and OLGA program performance. Note that NW Natural has retained Quantec to conduct an independent review of OLIEE. According to the 2003-2004 OLIEE Annual Report, Quantec's evaluation will address the following questions (among others):

- Do the current program structure, funding and practices provide optimal delivery?
- What are the bottlenecks in the program that impede complete implementation?
- Are there other channels for program delivery?
- Are there "best practices" from other states and programs that can be applied to this program?
- How are the funds expended? Is fund matching creating a bottleneck?

Because this evaluation is already in progress, we do not attempt to provide a complete evaluation of OLIEE. In addition, because the areas of inquiry established in the Commission's Order do not focus on OLIEE and OLGA program performance, we limit our examination of OLIEE and OLGA to the following:

1. To what extent do the CAP agencies value the OLIEE and OLGA funding provided by the Public Purposes charges?
2. What do the CAP agencies report with respect to NW Natural's efforts in administering the OLIEE and OLGA programs?

In order to address these issues, we contacted Jim Abrahamson, Oregon Energy Partnership Coordinator at Community Action Directors of Oregon, who then facilitated contact with the relevant staff members at the CAP agencies. We received feedback from four individuals regarding OLGA: Judy Schilling, Energy & Emergency Assistance Coordinator for Washington County; Karrie Durie of the Community Action Team; Terry Weygandt of the Community Services Consortium; and Margaret Davis of the Mid Columbia Community Action Council (MCCAC). We received feedback from two individuals regarding OLIEE: Jacque Meier, Weatherization Manager for Clackamas County and Joan Ellen Jones, Weatherization Manager for Washington County.

4.8.1 OLGA

The respondents were consistent in reporting the high value that their organizations place on the funding provided by OLGA. Judy Schilling's comments to us provide an example of this:

> As you probably know, the economy in Oregon is very depressed, energy costs are rising, and here in Washington County we have experienced a large growth in population in the past few years. I have been with the energy program for more than 20 years and I have never seen the demand for assistance as high as it is now. In the past, requests for help usually began declining after the coldest winter months. Now, the demand for assistance is high throughout the year. We find that many people end up turning off their gas altogether after the main heating season because they simply cannot afford to keep it on. They usually leave large arrearages

> which need to be paid in order to turn the gas back on in the fall. We often use OLGA for these situations, since our LIEAP funding is usually not available to us until December. We reply upon OLGA heavily in the months of September, October and November, just to get peoples' heat turned back on. If this program did not exist, many people would be completely without heat until December or January. Having OLGA as a year-round program helps in the summer, also, when all the LIEAP funding has been exhausted. Typically, we have no LIEAP dollars after April, so OLGA fills the gap between April/May and December. It is critical.

In addition, Margaret Davis and Karrie Durie reported that OLGA has allowed them to assist approximately 200 households each year.

Regarding their experiences in working with NW Natural, we received mostly positive feedback, along with some suggestions. Karrie Durie reported very positive experiences with NW Natural, noting that NW Natural has been prompt in responding to them, easy to work with (and easier to work with than other utilities), and that NW Natural's reporting requirements are not severe. She singled out Lois Douglass as being "great to work with". Her only recommendation was changing the OLGA calendar to a fiscal year that matches that of the state.

Judy Schilling was less positive regarding her interactions with NW Natural. She does not feel that NW Natural has been effective in communicating with the agencies in the planning and implementation of the program. In particular, she believes that using the state's existing energy assistance database instead of NW Natural's spreadsheets for tracking and reporting would eliminate extra work for the agency. In addition, she would like NW Natural to be more flexible with respect to changes in commitments (apparently no changes are allowed once the initial notification is posted to an account) and she would like to eliminate the $800 cap on the total benefits that a household can receive (including LIEAP funds).

Margaret Davis commented that the staff members that she has worked with at NW Natural have been "quick to respond, helpful, and always patient." She mentioned Lois Douglass, Gail Kamara and Angela Warren as being particularly helpful.

Terry Weygandt had the following comment in response to our question "In what ways has NW Natural been particularly helpful or unhelpful in assisting CAP agencies to maximize the performance of the OLIEE and OLGA programs? How could the relationship between NW Natural and CAP agencies be improved?"

> Since last September, many of the CAP agencies have been requesting a joint meeting with NW Natural to discuss this very topic. Our idea was to discuss what is working and what may not be working as well as we both would like. Unfortunately, we have not been successful in finding a date that would accommodate both NW Natural and the CAP providers. We understand NW Natural does not hold any admin funds from the OLGA

program and their staff is limited to the amount of time they can spend on OLGA issues.

At a minimum, I feel NW Natural and the OLGA providers should hold semi-annual meetings to discuss and facilitate change that would increase the effectiveness of OLGA and improve the relationship between NW Natural and the providing agencies. It is my understanding that the CAP providers are willing to travel to Portland if that would facilitate a meeting date.

Based on the feedback that we received, it appears that CAP agencies place a very high value on OLGA funding, that NW Natural has been helpful to them in many circumstances, but that there is room for improvement in the oversight of this program.

4.8.2 OLIEE

Both Jacque Meier and Joan Ellen Jones commented on the high value of the OLIEE program. Ms. Jones cited an example of the benefits that can come from this program:

The homes we work with are generally older and often under maintained. The heating systems are often, especially in the case of gas heated homes, not working or running in an inefficient, and/or unsafe manner. The families often use space heaters or in some cases cooking appliances to heat their homes. Without this assistance these households would continue to use space heaters, or perhaps install electric baseboard heat. These situations may be complicated by closed accounts and/or arrearages. Weatherization works with the energy assistance program for service reconnection, then completes repairs and in some cases replaces heating systems.

When there is no reported need for heating system service, weatherization requests are processed by a prioritization system based on points given for households with an elderly or disabled member, a child under six, or farm worker status. Though at a gas audit last week, the CO readings for the furnace were at such high levels that the test was immediately aborted and a service technician called. Without our intervention, the family would wonder why they were often sick, had headaches or perhaps worse. Their young pre-school children used the garage, where the furnace is located, as a play area.

Regarding her experience in working with NW Natural, Ms. Jones noted that she has a good working relationship with Ellen Prouty. She also had some suggestions for improving the program, including moving from reimbursement to up-front funding, that NW Natural acknowledge and assist with the safety and repair issues with gas heated homes, and help with the installation of 80% furnaces. Jacque Meier echoed the latter comment, based on the example that an 80% furnace is more efficient than the 70% furnace running at 50% efficiency (and producing carbon monoxide) it would likely replace. Therefore NW Natural should provide an incentive for the 80% furnace, which is more practical for these customers than a 90% high-efficiency furnace.

As with the OLGA program, the feedback that we received indicates that the CAP agencies place a high value on OLIEE funding and the agencies have had positive interactions with NW Natural staff, but that there are ways that they believe the program could be improved.

5. EVALUATION OF ALTERNATIVE RATE AND REGULATION OPTIONS

The DMN mechanism approved by the Commission is not the only way to address concerns about margin recovery and conservation. Indeed, NW Natural initially proposed a "full" decoupling mechanism that would allow for full fixed-cost recovery regardless of the source of usage changes (*i.e.*, that would not adjust actual usage for weather and would not include a 10% reduction in deferrals), while the Commission Staff has expressed a preference for a combination of price elasticity adjustments to adjust margin recovery for expected usage changes in response to price changes and lost revenue adjustments to compensate NW Natural for the adverse revenue effects associated with promoting energy efficiency. This section provides observations and analyses of some of the alternatives that have been proposed.

5.1 Fixed/Variable Rate Design

It is important to recognize that the original source of the problem of uncertain fixed-cost recovery due to usage variability, and thus the need for some form of decoupling, is the typical design of standard retail gas tariffs. That is, because a large percentage of fixed costs are recovered through volumetric (variable) rates, fixed cost recovery, and thus profits, depend on the level of sales. This design of recovering fixed costs primarily through variable energy prices has a number of implications, including the following:

1. The recovery of fixed costs through a volumetric rate creates weather-induced fixed-cost recovery risk for both the utility and its customers. For example, an unusually cold winter will cause customers to overpay for fixed costs, resulting in the utility over-recovering its fixed costs, while an unusually warm winter will cause the opposite result. This is a risk that can be "swapped" (*i.e.*, reduced or eliminated for both parties) by changing the method of fixed cost recovery.
2. The recovery of fixed costs through volumetric rates creates a disincentive for the utility to promote conservation that will reduce sales below the baseline level agreed upon in the most recent rate case for recovering allowed fixed costs.
3. The high variable price, which exceeds the market cost of natural gas, is appealing to environmentalists, as it provides a greater incentive for customers to engage in conservation efforts. The environmentalists justify this outcome based on the notion that a pure energy price that reflects private market costs does not account for the public externalities associated with energy consumption (*e.g.*, pollution). However, there is no direct link between the actual estimated externality cost associated with natural gas consumption and the fixed-cost margin by which the energy price exceeds the private marginal cost of natural gas. Furthermore, maintaining a retail energy price in excess of market costs invites

competition, such as from other fuel types, other states, or, where allowed, other suppliers.

4. The high variable price potentially offers customers a form of economic insurance. That is, if customers who fall on hard times reduce their usage, then the reduction in their bill will be larger than if the energy price covered only variable costs. That is, they would pay both reduced energy costs and a lower share of fixed costs. The cost of this insurance, however, is that for any increase in usage beyond their normal level, consumers pay for both additional energy and additional fixed costs.

A number of alternative rate structures have been considered that have the potential to alleviate one or more of the effects listed above. For example, a fixed/variable rate design, in which fixed costs are recovered primarily through fixed charges (*e.g.*, monthly customer charges and/or demand charges) and variable costs (*e.g.*, fuel costs) are recovered primarily through volumetric rates, eliminates all but the third concern listed above.[25] That is, with a fixed/variable rate design, fixed cost recovery is not sensitive to weather conditions. Secondly, because a fixed/variable rate design essentially ensures that fixed costs are recovered, the utility's disincentive to promote conservation is reduced or eliminated. Finally, it eliminates the possible economic insurance present in the variable pricing tariff, as customers who reduce their usage in response to declining incomes will receive bill reductions only for the reduction in fuel and other variable costs, but not a reduction in their contribution to fixed costs.

From an economic efficiency standpoint, fixed/variable pricing represents the most appropriate pricing method, as long as rates are set correctly to reflect fixed and variable costs, potentially including the addition of an explicit environmental externality component to the variable price. For this reason, we present this alternative to the current rate structure first, even though it has not been proposed recently by either NW Natural or the Commission. Two prominent objections have been raised that limit the use of fixed/variable pricing in Oregon's natural gas markets. These objections are the following:

1. *Equity concerns.* To the extent that natural gas use is correlated with income, increasing fixed charges relative to volumetric rates will adversely affect low income customers. We note that this concern can be largely alleviated by incorporating a demand charge in the fixed component of the rate, which would produce fixed charges that vary by customer size.
2. *Environmental concerns.* As noted above, reducing the volumetric price decreases customers' incentives to engage in conservation activities. This argument has some basis in theory to the extent that natural gas use imposes costs on the economy or environment that are not included in the price of energy.

[25] There are a number of examples of this form of pricing in both regulated and non-regulated industries, including local telephone service, cable television, health clubs, and some retail merchants such as Sam's Club. It is beyond the scope of this study to assess the industry or firm characteristics that increase the feasibility and/or use of fixed/variable pricing. However, we have considered that non-regulated merchants would likely trade off the benefits of a less variable revenue stream with the costs of restricting walk-in business when considering whether to adopt fixed/variable pricing.

However, this problem can be addressed directly by estimating the magnitude of externality costs and adding that amount to the retail energy price rather than allowing the average fixed cost to serve as the default estimate.

Because of the above concerns, fixed/variable rates have not received widespread support as a means of stabilizing cost recovery or reducing disincentives to promote energy efficiency.

5.2 Full Decoupling

NW Natural's original proposal to the Commission was for a full decoupling mechanism. The total revenue effects of this proposal are quite close to those of DMN and WARM in combination, but the mechanism is mathematically less complex. Equation 4 shows how full decoupling revenue adjustments are calculated.
Equation 4: Margin Adjustment = $M * C * (QPC^B - QPC^A)$

In this equation, M is the dollar per therm margin from the standard tariff; C is the number of customers to which the program applies; QPC^B is baseline use per customer; and QPC^A is actual use per customer. The key differences between this mechanism and the combination of DMN and WARM are as follows:

1. Actual use per customer is not adjusted for weather conditions. This results in an incorporation of a WARM-style adjustment into the decoupling mechanism.
2. Baseline quantities are not adjusted for prices.
3. The 90% factor used to reduce the amount of revenue variation covered by the DMN program is not included.
4. Weather-induced changes in revenue recovery accumulate in a deferral account instead of flowing to bills in the same month (as it works in WARM).
5. Because the DMN and WARM adjustments are combined in full decoupling, there is no need to set the price elasticity or define normal weather. Once the utility and the Commission agree on the allowed margin rate per customer, both parties have the incentive to select the "correct" value of baseline use per customer in order to minimize deferrals.

Because full decoupling is most appropriately compared to the combination of DMN and WARM (and not DMN alone) and we have yet to perform a detailed analysis of WARM outcomes, we must provide a caveat regarding the discussion that follows. That is, some of what we express here is an expectation that may or may not be supported by subsequent WARM data analyses.

Our belief is that full decoupling is easier to comprehend and communicate than the combination of DMN and WARM. This could reduce customer service costs associated with confusion about bills.[26] In addition, full decoupling eliminates disputes over setting

[26] Simplifying the mechanism would not reduce disputes about *whether* the bills should be adjusted, which will be reduced only to the extent that decoupling deferrals may be more difficult to detect than WARM bill adjustments.

parameter values about which reasonable people can disagree: the price elasticity and normal weather (heating degree days).

Full decoupling has a potential disadvantage with respect to the combination of DMN and WARM: under full decoupling, weather-induced revenue adjustments are deferred until the following year, while WARM adjustments affect current bills. To the extent that customers want to reduce the "cash flow" risk associated with weather-induced fluctuations in monthly bills, WARM provides superior benefits (that may be improved through modifications to the program). In fact, full decoupling could increase customers' weather risk. For example, if a mild winter is followed by an unusually cold winter, the surcharges caused by the mild winter could increase customer bills at exactly the wrong time. In short, full decoupling is not as effective as WARM in reducing customer's weather-induced bill risk. However, note that the *total* effect over time on customer bills is largely the same with full decoupling as it would be under the DMN + WARM mechanism, so customer's weather-induced *wealth* risk is nearly identical under the two mechanisms.

We have not yet performed an in-depth analysis of WARM data. Doing so may alter some of the preliminary conclusions presented in this section.

5.3 Elasticity and Lost Revenue Adjustments

In our discussions with them, Commission Staff proposed an alternative to DMN, which is to maintain the price elasticity adjustment, but replace the deferral component with lost revenue adjustments. We consider this proposal in four parts: the effects of removing the deferral component of DMN, the efficacy of lost revenue adjustments, the implications of removing NW Natural from energy efficiency promotions, and the effects associated with the potential elimination of Public Purposes Funding.

5.3.1 Elasticity Adjustment without Deferral Component

As noted earlier, there are two components to DMN. The first component adjusts margins for price changes using an assumed price elasticity value (*e.g.*, -0.172 for residential customers). For example, if the residential price increases by 10%, DMN assumes that residential use per customer will decline by 1.72% (which is derived by multiplying 10% by -0.172). The margin rate is then adjusted (increased in this example) so that the product of baseline use per customer and the margin is left unchanged. We will refer to this as the "elasticity adjustment." The second component of DMN, which we refer to as the "deferral component," provides for surcharges or refunds to customers based on 90% of the total margins associated with the difference between weather-normalized actual usage and price-adjusted baseline usage.

Provided that the assumed elasticity value is correct, the elasticity adjustment compensates NW Natural for lost margins associated with conservation efforts undertaken by customers (or, in the case of declining prices, load growth) outside of formal programs. The deferral component compensates NW Natural for lost margins associated with other non-weather effects, including the effects of NW Natural's and the Energy Trust's energy efficiency programs on use per customer. This component can also provide for recovery of lost margins caused by the use of an incorrect elasticity value in the calculation of the elasticity adjustment. (Of course, all margin recovery or refunds that occur through the deferral component are subject to a 10% reduction.)

Currently the deferral component serves several purposes:

1. It removes NW Natural's disincentive to promote energy efficiency.
2. It corrects 90% of the errors associated with an inaccurate elasticity adjustment.
3. When combined with WARM, it corrects 90% of the errors associated with the use of an incorrect normal weather measure.

The mechanics associated with the second and third purposes can be found in our overviews of DMN and WARM in Sections 2 and 3, respectively. For purposes of this section, it is sufficient to point out that eliminating the deferral component of DMN could lead an increase in disputes between the Commission and NW Natural over the price elasticity values and measures of normal weather. In short, removing the deferral mechanism increases the parties' incentives to "game" the elasticity adjustment and WARM parameters.

5.3.2 Lost Revenue Adjustments

An alternative to decoupling in general (and DMN in particular) is to compensate the utility for conservation efforts through lost revenue adjustments. For example, lost revenue adjustments as applied to the high-efficiency appliance program would compensate NW Natural for lost margins based on estimated therm reductions for each HEF adoption. This compensation occurs on a case-by-case basis and is not reconciled to actual therm reductions at any point.

There are a number of disadvantages associated with this approach to promoting conservation.[27]

1. It is administratively burdensome, requiring that energy efficient appliance adoptions be verified, and the energy-saving effects of each adoption estimated through costly program evaluations.
2. It addresses only those programs that *can* be verified or are associated with relatively easily counted adoptions. That is, lost revenue adjustments can be applied to high-efficiency furnace programs, but it would be difficult to use this mechanism for a program such as the Energy Trust's Efficient Facility Operations Program, in which a diverse set of actions may be taken to improve energy efficiency.
3. Lost revenue adjustments encourage programs that look good on paper, but do not actually deliver therm reductions.
4. With only lost revenue adjustments, the utility is discouraged from backing more general conservation efforts, such as pleas from the Governor to reduce consumption during an energy crisis, or proposals to improve energy efficiency

[27] Some of the disadvantages listed below are taken from "Breaking the Consumption Habit: Ratemaking for Efficient Resource Decisions" by Sheryl Carter, which appeared in the Electricity Journal in December 2001.

standards embedded in building codes. In addition, to the extent that specific energy efficiency messages (*e.g.*, promoting the HEF program) can spur more general conservation efforts, the utility program is left uncompensated by lost revenue adjustments.

5. Lost revenue adjustments do not protect the utility from margin loss due to independent conservation efforts (*i.e.*, conservation efforts undertaken by customers outside of formal programs with the intent of lower their bill). In times of increasing prices, this can require the utility to file rate cases more frequently, which imposes costs on the regulator and customers (indirectly, to the extent that rate case expenses can be recovered through rates). Conversely, in times of declining prices, lost revenue adjustments do nothing to prevent over-recovery on the part of the utility. (In principle, the elasticity adjustment accounts for this effect. However, its effectiveness is affected by the accuracy of the elasticity parameter, which can be difficult to estimate.)

The principle advantage of lost revenue adjustments relative to decoupling mechanisms is that they limit revenue adjustments to conservation efforts, while decoupling may compensate the utility for consumption declines due to economic or other factors. Our findings in Section 4.3 above, which analyzed the factors that affect residential and commercial use per customer for NW Natural's Oregon customers, indicates that this potential advantage is not relevant in NW Natural's case. That is, we found that the Oregon unemployment rate is not related to use per customer, and that retail prices and heating degree days explain the vast majority of variations in use per customer. Given this, it is unlikely that a significant share of DMN revenue flows can be attributed to customer responses to changing economic conditions.

Taking all of the above into account, our belief is that lost revenue adjustments will not be as effective as decoupling is in changing utility attitudes and actions with respect to promoting energy efficiency and other conservation efforts.

5.3.3 Effects of Removing NW Natural from Energy Efficiency Promotions

Because of the change in NW Natural's incentives that are associated with removing the deferral component, our expectation (shared by Marc Hellman of the Commission Staff in our meeting on January 28, 2005) is that NW Natural would revert to promoting load growth and shift resources away from promoting energy efficiency. The task of promoting energy efficiency would then shift entirely to the Energy Trust of Oregon (assuming that the Public Purposes Funding that supports this activity is maintained, which would likely be a contentious issue).

Based on our interviews with Margie Harris, Executive Director of the Energy Trust, and two distributors of high-efficiency furnaces,[28] removing NW Natural from the promotion of energy efficient appliances would harm program performance. Each of these people indicated that NW Natural's connections with distributors and customers enhance HEF program performance. Ms. Harris commented on replacing DMN with a lost revenue adjustment. Her belief is that DMN allows NW Natural to market energy efficiency

[28] The individuals interviewed were Mike Dawson of Gensco and Glen Bellshaw of Airefco.

more freely and have a more open and comprehensive approach to promoting energy efficiency. If NW Natural were to cease its promotion of energy efficiency, Ms. Harris believes that the Energy Trust would have to work hard to build the connections to vendors and customers that NW Natural currently provides. Given that she sees no disadvantages associated with DMN and has had (overall) a positive experience in partnering with NW Natural in promoting energy efficiency, she supports the continuation of DMN.

The distributors with whom we spoke concurred with Ms. Harris' opinion. From their perspective, DMN has produced uniformly positive outcomes and they would support its renewal.

Some evidence of NW Natural's effectiveness in helping to promote Energy Trust initiatives is provided by Energy Trust call center tracking data. Two types of information are available on a monthly basis beginning in October 2004: the share of referrals for total call center intake by source, and the share of Home Energy Savings Program routings by source. These are presented in Tables 5-1 and 5-2 below.

Table 5-1: Share of Total Call Center Referrals by Source

Source	October 2004	November 2004	December 2004	January 2005
PGE	6	7	7	10
PacifiCorp	5	5	5	5
NW Natural	11	11	14	14
Other	78	77	74	71

Table 5-2: Share of Home Energy Savings Routings by Source

Source	October 2004	November 2004	December 2004	January 2005
PGE	8	10	9	13
PacifiCorp	6	6	7	7
NW Natural	16	16	21	19
Other	70	68	63	61

These tables show that NW Natural, which accounts for a small share of Energy Trust funding relative to PGE and PacifiCorp (about $6 million for NW Natural, versus about $45 million for PGE and PacifiCorp), accounts for a comparatively high percentage of referrals to the Energy Trust call center.

5.3.4 Effects of Eliminating Public Purposes Funding

As a part of its decoupling proposal, NW Natural included provisions for Public Purposes Funding for three purposes: low-income bill payment assistance, low-income weatherization assistance, and enhanced energy efficiency programs.

According to budgeted 2004 figures, the low-income bill payment assistance (OLGA) fund collected about $1.44 million in 2004, the low-income weatherization assistance

(OLIEE) fund collected about $1.35 million in 2004 and the energy efficiency fund collected about $6.75 million ins 2004. In an initial meeting regarding this study, Steve Weiss of the Northwest Energy Coalition asserted that the benefits associated with these funds should be included in the benefits of DMN to the extent that NW Natural will remove their support for Public Purposes Funding if decoupling is eliminated. In addition, Bob Jenks of the Citizens' Utility Board of Oregon supports DMN solely because of the presence of the Public Purposes Funding. Finally, the feedback we received from CAP agencies (presented in Section 4.8) indicates that they place a high value on the OLGA and OLIEE programs.

5.4 Conclusions Regarding Rate Structures

Both full decoupling and the combination of DMN and WARM, in conjunction with recovery of fixed costs through variable energy prices, have the following effects relative to standard rates and regulatory mechanisms:

1. They reduce or eliminate the utility's disincentive to promote energy efficiency.
2. They maintain an added incentive for individual consumers to undertake conservation efforts, through retail prices that exceed market costs of energy.
3. They reduce utilities' variability of fixed-cost recovery.

These two mechanisms are the only alternatives discussed here that have these three characteristics. A fixed/variable rate design would reduce variability in fixed-cost recovery, but does not maintain the high volumetric price. Replacing the deferral mechanism with lost revenue adjustments does not effectively reduce the utility's disincentive to promote energy efficiency (and, importantly, reinstates an incentive to promote load growth relative to decoupling mechanisms).

Given that our research on recent historical changes in prices, economic factors and energy consumption indicates that neither DMN nor full decoupling is likely to cause a shift of economic risk from NW Natural to its customers, we believe that full decoupling or DMN are the approaches that are likely to both:

- Meet the desired goals of allowing NW Natural to promote energy efficiency without harming its shareholders, while stabilizing fixed cost recovery; and
- Alleviate concerns about maintaining incentives to consumers to privately undertake conservation efforts and avoid potentially harmful distributional effects (that could be caused by higher fixed customer charges in a fixed/variable rate design).

A determination of whether full decoupling or a combination of DMN and WARM is a superior approach primarily depends on the effects that the two methods have on individual customer bills when weather deviates from normal conditions. An in-depth analysis of this topic is outside the scope of this report, but will be completed as part of a follow-up review that focuses on the effectiveness of WARM.

6. CONCLUSIONS AND RECOMMENDATIONS

6.1 Responses to Commission Questions

In Order 02-634 establishing DMN, the Commission required that this independent study address a number of questions. As part of the review process, Commission Staff added several issues to this list. As an initial step in providing conclusions and recommendations, we provide direct answers to those questions.[29] The questions appear in italics, and our responses appear as standard text.

1. *a. Did the mechanics of DMN accurately carry out the intentions of the Specified Parties and the Commission as expressed in this Agreement?* In August and September of 2004, an independent consultant named Gary Hill reviewed and audited the calculations performed for DMN. NW Natural commissioned this review as a precaution against the more strict accounting standards imposed by the Sarbanes-Oxley Act of 2002. Appendix 2 contains a letter from Mr. Hill to Alex Miller of NW Natural certifying the accuracy of the DMN calculations. In the interest of cost efficiency, we did not perform a separate audit of the DMN calculations. However, based on Mr. Hill's report, it appears that the DMN calculations as executed by NW Natural accurately reflect the intentions in the Agreement.

   b. To the extent lost margins have been recovered through DMN, what percentage of the margins recovered were due to conservation, economic activity, and price changes? We are unable to determine the exact percentages of recovered margins associated with these three factors. However, our analysis of factors that have affected recent historical changes in residential and commercial use per customer (in Section 4.3) indicates that the vast majority of DMN margin adjustments can be attributed to the effect of price changes. That is, economic activity (represented by the Oregon unemployment rate) and NW Natural-sponsored conservation efforts (the residential HEF program) have not had a statistically significant effect on use per customer. We provide one caveat to this conclusion, to the effect that to some extent, consumers' usage changes in response to price changes overlap with "conservation," in that the price elasticity effect occurs through a combination of short- and long-run changes in customer behavior. These can include actions such as turning the thermostat down, as well as adding insulation or purchasing higher efficiency equipment. To the extent that NW Natural's promotion of specific energy efficiency programs has general conservation effects (through increased awareness), price effects overlap with conservation effects.

2. *Did DMN effectively remove the relationship between the utility's sales and profits?* Our analysis of the DMN mechanism indicates that it is effective in reducing, but not completely removing, the link between utility sales and profits. Through simulations (described in Section 4.1), we estimate that DMN reduces the variability of residential margins per customer by 30 percent and reduces the variability of commercial margins per customer by 42 percent.

[29] We have eliminated some WARM-specific issues that will be addressed in a separate report.

There are two reasons that DMN does not remove the relationship entirely. First, it excludes weather effects (which are subsequently accounted for through the WARM mechanism). Second, a 90% factor is applied to the deferral component. Still, according to CFO David Anderson, DMN has been effective in reducing the link between NW Natural's sales and its profits. Our simulation of DMN revenue effects (in Section 4.1) indicated the possibility that the assumed price elasticity values may be too low (in absolute value), which exposes a larger share of the revenue adjustments to the 90% factor in the deferral calculations. Updating the elasticities and/or removing the 90% factor could further reduce the link between sales and profits.

3. *Did DMN effectively mitigate the utility's disincentives to promote energy efficiency?* An examination of the theoretical effects of DMN leads us to conclude that it is an effective means of reducing NW Natural's disincentive to promote energy efficiency. This conclusion is reinforced by NW Natural's actions under DMN, which include effectively partnering with the Energy Trust of Oregon, improving HEF program performance, and shifting marketing resources towards energy efficiency promotions. (It is possible that the shift in marketing resources can be attributed in part to Order 99-697, in which the Commission disallowed recovery of image advertising expenses.)
4. *Did DMN improve the utility's ability to recover its fixed costs?* This question is closely related to Question #2 above, in that reducing the link between sales and profits will produce more stable recovery of fixed costs. Therefore, for the reasons stated above, we conclude that DMN has improved NW Natural's ability to recover fixed costs.
5. *a. Did DMN reduce business and other financial risks?* Yes, by reducing revenue fluctuations DMN has reduced NW Natural's risk.

   b. If yes, describe the risks and estimate the reduced costs to the Company associated with the business and financial risks that were impacted. As described in Section 4.5, CFO David Anderson believes that DMN and WARM were contributing factors to NW Natural obtaining the best rating in the Standard & Poor's (S&P) business risk profile (scoring a 1 on a scale of 1 to 10). Similarly, he believes that DMN and WARM contributed to the upgrade in NW Natural's S&P bond rating from A to A+. An improved risk profile has several beneficial effects. It allows NW Natural to maintain smaller lines of credit, reduce the share of equity in its capital structure, and maintain a lower coverage ratio. However, it is difficult to quantify these effects for two reasons. First, given that a number of events occurred that are unrelated to DMN and WARM (most prominently, the completion of general rate case UG-152), it is difficult to attribute changes in risk profiles or finances to any one cause. Second, given the changes in financial markets over time, we cannot simply attribute changes in interest rates to changes in NW Natural's risk profile. That is, interest rates fluctuate throughout the economy, so a reduction in interest rates may be due entirely to effects that are independent of NW Natural's circumstances.

   c. If yes, did the Company increase its efforts and activity on non-regulated activities? According the CFO David Anderson, non-regulated activities account for only about 3% of assets, and the risk reductions afforded by DMN and WARM did not affect non-regulated activities.

d. What was the level of impact and effects on operations? In addition to the potential effects on financial measures described above, DMN contributed to organization changes that are described in Section 4.4 and in response to question 7b below.

e. Were the reduced risks shifted away from the Company to customers or a third party or eliminated? In Section 2.2, we describe how DMN affects risk for NW Natural and its customers. Four sources of uncertainty were considered: weather, natural gas prices, economic conditions, and other random factors. We summarize the effect of DMN on the risk produced by each of these sources of uncertainty below.

Weather risk is not affected by DMN because of the weather normalization of usage that is incorporated in the deferral mechanism. Uncertainty in the price of natural gas affects the amount of natural gas that customers will use. The risk that NW Natural faces with respect to gas prices is that when prices rise, customer usage levels decrease, reducing fixed cost recovery. At the same time, the price increase causes customers' bills to increase (as long as any reductions in usage are not offset by the increase in the gas price). By reducing or eliminating the risk to NW Natural associated with uncertain gas prices, this risk to customers is increased. However, the element of DMN that shifts this risk is the elasticity adjustment, over which there appears to be no dispute with respect to its appropriateness. That is, various parties' views regarding the efficacy of DMN seem to hinge on their opinion of the decoupling mechanism, not the elasticity adjustment.

In theory, DMN could shift economic risk from the utility to customers. For example, if the regional unemployment rate increases, residential customers might lower their thermostat settings in an attempt to reduce their bills. DMN insures NW Natural against lost margins associated with reduced sales from this type of action. However, our findings from an analysis of recent historical data indicate that NW Natural's residential and commercial use per customer do not appear to be sensitive to such economic conditions. Therefore, we conclude that a shift of economic risk from NW Natural to its customers does not occur in NW Natural's service territory.

f. What impact did DMN and WARM have on the need for, or cost, of new security issuances or lines of credit? As described in Section 4.5, NW Natural CFO David Anderson believes that the presence of DMN and WARM have allowed NW Natural to retain smaller lines of credit and have a lower share of equity (*i.e.*, reduced the need for new security issuances).

h. What incremental impacts have DMN and WARM had on NW Natural's bond ratings? NW Natural CFO David Anderson believes that the risk mitigating effects of DMN and WARM contributed to an increase in NW Natural's Standard & Poor's bond rating from A to A+.

i. How does NW Natural's revenue variability compare to a representative sample of LDCs before and after DMN and WARM? This issue is addressed in Section 4.2, which shows that NW Natural's revenue variability is lower than the average utility *in the representative sample used. Because relatively little time has passed since* DMN was put in place, we did not compare the revenue variability both before and after DMN was implemented.

6. *Did DMN affect, positively or negatively, levels of service quality or the company's incentives to provide excellent service quality?* As shown in Section 4.6, DMN does not appear to have adversely affected NW Natural's level of service quality. This is consistent with our analysis of the incentive effects associated with DMN, which indicate that DMN does not alter NW Natural's incentives to provide high quality customer service.

7. *a. What changes in company culture or operating practices resulted from the implementation of DMN?* This issue is discussed in Section 4.4. The changes that may be attributed to DMN are a shift in marketing efforts (though this may also be due to a change in Commission policy with respect to allowed costs), taking a public stance that strongly supports energy efficiency, and shifting compensation policies (by adopting specific individual incentives and moving away from commission).

   b. What organizational changes and/or Company communications to NW Natural employees resulted from the changes to company culture or operating practices? As described in Section 4.4, a number of organizational changes occurred following the implementation of DMN. While it is difficult to quantify the extent to which these changes were brought about directly by DMN, Grant Yoshihara of NW Natural estimated that about 50% of the shift of personnel from sales and promotions (which decreased from 67 FTEs in 2002 to 20.5 FTEs in 2005) to customer service (which increased from 18 FTEs in 2002 to 44 FTEs in 2005) was due to a change in philosophy that is consistent with the incentives provided by DMN.

   c. What impact, if any, did DMN and WARM have on uncollectibles, new hookups, NW Natural's line extension policy and actions specific to natural gas customers? As discussed in Section 4.7, DMN had no effect on NW Natural's pursuit of uncollectible accounts. A discussion of new connections customers and NW Natural's line extension policy is contained in Section 4.4 and in response to question 8 below.

8. *How do usage and revenues associated with new connects compare to the base usage and revenues assumed in DMN?* Section 4.4 presents the limited information that we have to answer this question. We have seen mixed evidence, indicating that residential new connections and commercial conversion customers tend to have lower usage levels than existing customers, while commercial new construction customers have higher usage than existing customers. However, a number of other factors could be affecting this analysis (*e.g.*, small sample size for commercial new connections; and changes in building codes, building materials, and appliance efficiency levels in residential housing). In addition, our review of NW Natural's methods for evaluating new connections and conversion customers revealed that DMN revenue adjustments are not included. Based on this, we conclude that NW Natural has not "gamed" the DMN mechanism with respect to new connections customers.

9. *What impacts has DMN had on customers?* As shown in Section 4.1, the first year of DMN produced almost $15 million in surcharges to customers, or about 3 percent of

total residential and commercial revenues. This relatively high amount was due to the fact that baseline usage was set at a time when prices were substantially lower, thus requiring a large first-year DMN adjustment. In its second full year, DMN produced a much lower surcharge of about $578,000, or about 0.1% of total residential and commercial revenues. Customer complaint data show that negative views of DMN were limited to objections regarding the appropriateness and/or legality of imposing Public Purposes Funding charges on customer bills. The absence of complaints regarding the DMN mechanism could be due to a low awareness of the program, which (if true) could be caused by the fact that DMN adjustments are not separately listed on customer bills.

Public Purposes Funding approved in combination with DMN has provided about $1.4 million per year in low-income bill payment assistance, $1.3 million per year in low income weatherization funds, and $6.75 million per year for energy efficiency programs (*i.e.*, Energy Trust funding). (The values listed here are based on 2004 budgeted amounts.)

6.2 Recommendations

Based on the information and input that we have received and reviewed, we recommend that some form of revenue decoupling be retained. It has been effective in reducing the variability of distribution revenues and in altering NW Natural's incentives to promote energy efficiency. While DMN does not provide an *incentive* for NW Natural to promote energy efficiency, it does remove most of the *disincentive* that exists with the standard rates.

We have been impressed by the breadth of support that DMN has received. The Energy Trust of Oregon reports that NW Natural has been successful in creating a good working relationship with the Energy Trust, and that NW Natural's efforts to promote energy efficiency effectively complement their own efforts. HVAC distributors believe that NW Natural's marketing efforts, in conjunction with its relationships with consumers, distributors, and the Energy Trust have helped increase sales of high-efficiency furnaces to the point where Oregon has the highest share of high-efficiency furnaces in the nation (as a percentage of new furnace sales). The Citizens' Utility Board of Oregon, the Northwest Energy Coalition and a number of CAP agencies believe that the Public Purposes Funding established in conjunction with DMN is beneficial for consumers. The Natural Resources Defense Council and American Gas Association released a joint statement regarding the positive environmental effects of decoupling, specifically citing NW Natural's experience as an example of the positive outcomes that decoupling can yield. The negative feedback that we have received is limited to twenty-six customer complaints that questioned the appropriateness and/or legality of the Public Purposes Funding.

In our discussions with the Commission Staff, they expressed several concerns about DMN. We summarize the concerns and our evaluation of them below.

- *Concern that DMN might shift economic risk from NW Natural to customers.* In theory, DMN could shift economic risk from NW Natural to customers. That is, if use per customer declines during economic downturns, the DMN deferral mechanism would produce a surcharge that would offset some of the bill reductions that customers would otherwise experience. We found that this concern, while valid in theory, is not likely to be relevant in practice in NW Natural's Oregon service territory. We conducted a time series analysis of residential and commercial use per customer that indicated that use per customer is strongly affected by weather and changes in energy prices, but not significantly affected by economic conditions. Therefore, we do not believe that a significant portion of deferrals can be attributed to changes in economic conditions.

- *The deferral mechanism would be unnecessary if very little of it is caused by NW Natural sponsored conservation efforts.* It is true that a very small percentage of the deferral revenues can be attributed to NW Natural sponsored conservation efforts (specifically, the residential HEF program). However, NW Natural and the Energy Trust of Oregon agree that the DMN deferral mechanism gives NW Natural the freedom to be more aggressive in its promotion of energy efficiency.

  In addition, the deferral mechanism allows for the determination of the price elasticity values to be less contentious. In DMN's current form, when an error is made in setting the price elasticity, the deferral mechanism will correct 90% of the error. Given the range of short- and long-term responses that customers can make to price changes (*e.g.*, temporarily turn down the thermostat or permanently change appliances and/or fuel sources), price elasticity values are difficult to estimate and apply with precision.

  Finally, both the Commission Staff and NW Natural agree that NW Natural should be compensated for lost margins due to energy efficiency programs. The Commission Staff has proposed replacing the deferral mechanism with a lost revenue adjustment. Section 5.3.2 contains a discussion of the reasons that lost revenue adjustments are likely to be inferior to deferral mechanisms (*i.e.*, lost revenue adjustments are administratively burdensome, produce incentives to create programs that look good on paper but perform poorly in reality, and do not compensate the utility for general conservation efforts). The deferral mechanism expands the range of conservation programs and policies that NW Natural can support without harming its shareholders. Examples programs or policies that would be less tenable with lost revenue adjustments are conservation programs that are difficult to track (such as the Energy Trust's Efficient Facility Operations Program), supporting more energy efficient building standards, or supporting pleas for conservation during an energy crisis. In addition, to the extent that successful energy efficiency campaigns spur conservation efforts outside of the program, lost revenue adjustments do not adjust for the reduction in distribution revenues while DMN will.

- *It is appropriate for NW Natural to have an incentive to grow and to fully transfer the promotion of energy efficiency promotion to the Energy Trust of Oregon.* This view is contradicted by the views of the Energy Trust and HVAC distributors, who believe that NW Natural's involvement in the promotion of energy efficiency has improved program performance. By eliminating the deferral mechanism, NW Natural's incentives would oppose those of the Energy Trust, which would endanger the relationship that they have developed.

There is one negative incentive effect that DMN provides with respect to conservation: it reduces NW Natural's incentive to promote natural gas water heater conversions for current customers because each conversion would produce a short-term revenue loss through the deferral mechanism. In addition, DMN provides a short-term incentive to bias new customer connections policies toward smaller customers. On balance, however, it appears that the combination of Public Purposes Funding and NW Natural's improvements in HEF program performance outweigh these concerns.

We believe that the positive effects of DMN outweigh the negative effects. However, there are several ways in which DMN might be improved.

1. Eliminate the 90% factor applied to the deferral adjustments. This factor introduces incentives to manipulate parameter values, reduces the positive incentive effects of DMN, and can reduce refunds to customers as well as surcharges. There do not appear to be any positive incentive effects of this factor with respect to the performance of DMN, therefore it should be removed.
2. Re-evaluate the price elasticity values agreed to in the Order. Our research indicates that the values currently used may be too low (in absolute value). The use of price elasticity values that are too low will tend to increase the amount of revenues that flow through the deferral mechanism rather than the elasticity adjustment. This delays price-related revenue adjustments until the following year and, because of the 90% factor currently used, reduces the amount of revenue that is adjusted for price changes.
3. Re-evaluate the weather sensitivity parameter (β) used in WARM and DMN. In particular, it appears that the residential class value may be too high. Based on the information that we have seen, the methods used to initially estimate β values appear to be sound, so it may be that only the data used in the estimation needs to be updated. In addition, consideration should be given to estimating a weather sensitivity parameter expressed in units of *percentage* changes in use per HDD rather than *levels* of use, or customer-specific parameters.
4. Consider adopting full decoupling. Because of its simplicity, full decoupling would be easier for customers to understand than the combination of DMN and WARM. In addition, full decoupling does not have some of the gaming incentives present in DMN (which could also be eliminated by removing the 90% factor applied to deferral calculations). However, because full decoupling encompasses the effects of both DMN and WARM (because full decoupling does not weather normalize usage), a decision on this matter should be delayed until a more complete analysis of WARM has been conducted. In particular, customers may prefer the fact that WARM provides adjustments to current bills, whereas

weather-related revenue adjustments are deferred until the following year under full decoupling.

Appendix Table A1
Revenue Variability Data for the Comparison Sample of Utilities

		Residential			Commercial					
Utility	Year	# Accounts	Sales	Revenues ($000)	# Accounts	Sales	Revenues ($000)	HDD	# Accounts	Sales Units
AGL	1993	1,182,700	100,140	658,200	95,700	47,850	268,100	2,852	Avg	MDth
AGL	1994	1,215,200	100,310	700,700	98,000	47,890	285,800	2,565	Avg	MDth
AGL	1995	1,250,400	91,680	610,600	100,000	45,400	243,200	2,121	Avg	MDth
AGL	1996	1,289,400	116,540	708,800	102,500	53,820	288,800	3,191	Avg	MDth
AGL	1997	1,319,000	98,610	728,500	104,500	45,550	290,900	2,402	Avg	MDth
Atmos	1993	789,360	74,818	372,770	86,124	36,307	165,611	4,080	Yr end	MMcf
Atmos	1994	825,310	72,561	375,450	93,250	35,250	165,883	3,855	Yr end	MMcf
Atmos	1995	834,376	69,666	337,768	90,093	34,921	150,949	3,706	Yr end	MMcf
Atmos	1996	860,229	77,001	409,039	91,960	38,247	186,032	4,043	Yr end	MMcf
Atmos	1997	870,747	75,215	452,864	92,703	37,382	193,302	3,909	Yr end	MMcf
Atmos	1998	889,074	73,472	410,538	94,302	36,083	184,046	3,799	Yr end	MMcf
Atmos	1999	919,012	67,128	349,691	98,268	31,457	144,836	3,374	Yr end	MMcf
Atmos	2000	970,873	63,285	405,552	140,019	30,707	176,712	2,096	Yr end	MMcf
Atmos	2001	1,243,625	79,000	788,902	122,274	36,922	342,945	4,124	Yr end	MMcf
Atmos	2002	1,247,247	77,386	535,981	122,156	35,796	221,728	3,368	Yr end	MMcf
Atmos	2003	1,498,586	97,953	873,375	151,008	45,611	367,961	3,473	Yr end	MMcf
Atmos	2004	1,506,777	92,208	923,773	151,381	44,226	400,704	3,271	Yr end	MMcf
Cascade	1994	112,533	8,391	47,011	21,835	9,570	50,116	5,301	Yr end	MDth
Cascade	1995	120,096	9,352	56,816	22,797	10,115	58,145	5,607	Yr end	MDth
Cascade	1996	127,794	10,178	62,076	23,827	10,343	59,402	5,620	Yr end	MDth
Cascade	1997	135,126	11,014	65,324	24,591	10,731	55,132	5,525	Yr end	MDth
Cascade	1998	142,645	10,645	65,926	25,415	9,988	52,735	5,031	Yr end	MDth
Cascade	1999	150,296	11,991	77,925	26,305	10,696	59,548	5,535	Yr end	MDth
Cascade	2000	157,443	12,185	85,728	27,151	10,672	65,294	5,372	Yr end	MDth
Cascade	2001	162,568	12,678	115,974	27,491	11,182	92,099	5,793	Yr end	MDth
Cascade	2002	169,476	12,921	130,582	28,098	10,728	98,195	5,455	Yr end	MDth
Cascade	2003	176,986	12,262	121,026	28,615	10,019	89,136	5,042	Yr end	MDth
Cascade	2004	184,315	13,127	130,727	29,009	10,649	95,629	5,212	Yr end	MDth
Energen	1997	423,130	29,008	243,876	34,432	12,976	91,517		Avg	MMcf
Energen	1998	423,758	27,925	224,934	34,719	12,664	82,520		Avg	MMcf
Energen	1999	427,159	26,001	218,638	35,137	12,049	80,802		Avg	MMcf
Energen	2000	430,069	27,369	256,591	35,586	12,629	99,356		Avg	MMcf
Energen	2001	427,584	28,962	353,358	35,778	12,909	139,046		Avg	MMcf
Energen	2002	425,630	26,358	277,088	35,601	11,838	104,247		Avg	MMcf
Energen	2003	427,413	27,248	320,938	35,463	12,564	126,638		Avg	MMcf
Laclede	1993	555,467	61,906	348,494	36,514	29,321	136,462	4,838	Yr end	MDth
Laclede	1994	559,225	61,086	363,058	36,684	28,917	142,042	4,694	Yr end	MDth
Laclede	1995	566,421	54,178	302,770	37,409	25,691	109,270	4,005	Yr end	MDth
Laclede	1996	569,818	64,237	376,818	37,735	30,948	145,466	4,880	Yr end	MDth
Laclede	1997	572,794	60,633	395,250	37,985	29,622	152,222	4,953	Yr end	MDth
Laclede	1998	577,224	56,073	365,768	38,519	25,921	132,504	4,404	Yr end	MDth
Laclede	1999	582,719	53,092	324,115	39,041	24,514	112,890	4,140	Yr end	MDth
Laclede	2000	586,783	49,549	346,159	39,419	22,831	123,578	3,933	Yr end	MDth
Laclede	2001	584,269	60,784	619,090	39,264	28,044	250,741	5,102	Yr end	MDth
Laclede	2002	588,630	50,216	387,594	39,842	24,053	142,259	3,959	Yr end	MDth
Laclede	2003	590,785	57,719	502,071	40,166	25,653	188,688	4,803	Yr end	MDth
Laclede	2004	591,547	52,490	543,996	40,417	22,914	202,183	4,102	Yr end	MDth
Nicor	1997	1,710,000	233,200	1,126,000	161,700	65,200	314,800	6,254	Yr end	MMcf
Nicor	1998	1,737,600	192,400	813,600	163,800	44,300	189,400	4,834	Yr end	MMcf
Nicor	1999	1,769,200	209,000	899,800	166,100	39,800	172,300	5,272	Yr end	MMcf
Nicor	2000	1,799,100	219,000	1,353,900	167,600	38,400	236,000	5,717	Yr end	MMcf
Nicor	2001	1,824,600	201,500	1,486,400	168,700	37,200	274,600	5,422	Yr end	MMcf
Nicor	2002	1,860,400	212,900	1,057,400	171,300	41,600	209,400	5,779	Yr end	MMcf
Nicor	2003	1,890,300	214,900	1,611,900	172,800	46,700	351,700	6,068	Yr end	MMcf
NW Natural	1993	329,157	26,782	168,217	42,657	20,964	103,476	4,452	Yr end	MDth
NW Natural	1994	346,950	26,022	176,510	44,078	20,193	108,452	4,020	Yr end	MDth

Appendix Table A1
Revenue Variability Data for the Comparison Sample of Utilities

NW Natural	1995	363,903	25,646	165,662	45,402	19,672	99,079	3,779	Yr end	MDth
NW Natural	1996	385,213	30,631	183,802	47,309	22,512	104,582	4,427	Yr end	MDth
NW Natural	1997	407,061	30,636	177,835	50,315	22,525	100,677	4,092	Yr end	MDth
NW Natural	1998	425,606	31,569	205,388	51,159	22,912	117,889	4,011	Yr end	MDth
NW Natural	1999	447,659	35,297	242,952	52,870	25,238	139,425	4,256	Yr end	MDth
NW Natural	2000	468,087	35,638	280,642	54,684	25,038	159,660	4,418	Yr end	MDth
NW Natural	2001	485,207	35,007	329,905	55,096	24,229	190,236	4,325	Yr end	MDth
NW Natural	2002	503,402	35,709	354,735	56,087	24,016	201,475	4,232	Yr end	MDth
NW Natural	2003	519,427	34,353	328,464	57,969	22,626	176,385	3,952	Yr end	MDth
Peoples	1993	904,316	144,199	929,407	50,736	26,185	156,377	6,679	Avg	MDth
Peoples	1994	905,461	142,876	951,037	50,955	26,206	160,912	6,701	Avg	MDth
Peoples	1995	906,681	130,571	752,796	50,872	22,079	116,113	5,897	Avg	MDth
Peoples	1996	910,236	154,128	883,100	50,719	27,390	141,594	7,080	Avg	MDth
Peoples	1997	910,657	142,837	941,557	50,914	24,994	146,412	6,806	Avg	MDth
Peoples	1998	908,025	119,206	780,168	46,639	19,501	112,166	5,564	Avg	MDth
Peoples	1999	911,782	117,840	727,095	44,382	17,411	95,530	5,646	Avg	MDth
Peoples	2000	919,196	117,814	836,761	48,540	18,974	122,350	5,650	Avg	MDth
Peoples	2001	931,151	127,536	1,439,364	46,160	19,350	204,629	6,713	Avg	MDth
Peoples	2002		113,322	794,865		17,345	109,307	5,639		MDth
Peoples	2003		128,521	1,155,927		21,555	178,845	6,684		MDth
Peoples	2004		116,939	1,148,499		20,303	184,756	6,091		MDth
Piedmont	1993	396,394	34,277	221,632	54,451	28,179	154,894	3,659	Avg	MDth
Piedmont	1994	420,861	36,093	240,314	56,147	28,931	165,805	3,567	Avg	MDth
Piedmont	1995	446,118	33,513	229,546	57,803	22,867	135,933	3,144	Avg	MDth
Piedmont	1996	468,803	43,357	292,010	59,905	31,040	180,415	3,993	Avg	MDth
Piedmont	1997	495,739	38,339	319,722	62,258	28,476	195,862	3,471	Avg	MDth
Piedmont	1998	522,451	41,142	323,777	63,878	28,528	189,341	3,339	Avg	MDth
Piedmont	1999	549,610	38,111	295,108	66,409	26,668	168,731	3,124	Avg	MDth
Piedmont	2000	577,314	40,520	343,476	68,879	29,315	207,087	3,097	Avg	MDth
Piedmont	2001	601,682	47,869	525,650	71,069	31,002	299,672	3,821	Avg	MDth
Piedmont	2002	620,642	40,047	358,027	72,323	25,892	191,988	3,004	Avg	MDth
Piedmont	2003	657,965	52,603	524,933	75,924	33,648	299,281	3,643	Avg	MDth
Piedmont	2004	771,037	54,412	624,487	90,328	35,483	360,355	3,331	Avg	MDth
SEMCO	1993		23,302	122,216		12,608	61,379	7,053		MMcf
SEMCO	1994		23,437	121,066		12,469	59,413	6,861		MMcf
SEMCO	1995		24,676	115,242		12,738	54,763	7,158		MMcf
SEMCO	1996		26,703	138,644		13,670	65,509	7,099		MMcf
SEMCO	1997		25,968	139,538		13,483	66,577	6,838		MMcf
SEMCO	1998		21,946	118,220		8,840	42,041	5,566		MMcf
SEMCO	1999		28,583	137,407		8,882	38,451	6,650		MMcf
SEMCO	2000		41,397	190,221		14,591	62,354	7,293		MMcf
SEMCO	2001		41,529	201,754		16,032	73,831	7,038		MMcf
SEMCO	2002		42,671	227,086		16,970	84,480	7,394		MMcf
Southwestern	1999		55,451			26,603		1,928		MDth
Southwestern	2000		57,138			27,267		1,938		MDth
Southwestern	2001		58,994			27,997		1,963		MDth
Southwestern	2002		58,822			28,027		1,912		MDth
Southwestern	2003		59,305			27,915		1,772		MDth
WGL	1995		59,650			40,318		3,680		MDth
WGL	1996	711,837	73,960	551,943	59,603	47,365	303,011	4,570	Yr end	MDth
WGL	1997	736,513	66,545	574,590	61,400	42,683	307,769	3,876	Yr end	MDth
WGL	1998	756,682	61,579	514,713	62,210	34,581	245,572	3,662	Yr end	MDth
WGL	1999	782,648	60,416	487,869	62,919	28,535	195,592	3,652	Yr end	MDth
WGL	2000	810,855	55,783	477,185	64,169	24,024	181,674	3,637	Yr end	MDth
WGL	2001	837,993	63,495	756,709	65,031	25,855	272,849	4,314	Yr end	MDth
WGL	2002	872,362	50,924	517,798	66,168	19,392	163,235	3,304	Yr end	MDth
WGL	2003	892,382	64,881	737,264	66,804	23,963	239,907	4,550	Yr end	MDth
WGL	2004	921,767	62,973	792,999	67,564	22,641	245,242	4,024	Yr end	MDth

Appendix 2: Summary of the Review of the Decoupling Methodology by Gary C. Hill

September 14, 2004

Mr. Alex Miller
NW Natural
220 NW Second Avenue
Portland, Oregon 97209

Dear Alex

Subject: Review of NW Natural Decoupling Methodology

I have completed my review of the methodology for determining NW Natural's decoupling adjustment which provides for residential and commercial margins based on a baseline amount of volume. I have reviewed the overall methodology as well as the model, which is the basis for determining the baseline usage that is required for the monthly decoupling journal entry

To complete the review of the overall methodology, Company documents were reviewed that summarized the process employed for calculating the adjustment. These included the following summaries: NW Natural Decoupling Methodology, NW Natural Decoupling Mechanism – Development of Commercial Baseline Usage and Development of Residential Baseline Usage. Supporting documents were reviewed to provide background and validate that the actual model corresponded to the decoupling methodology as described. These documents included the Oregon PUC Order No. 02-634, Monthly JV 35, rate schedules 190 and 195 plus the derivation of margin change due to elasticity. The reclassification of customers from residential to commercial, and between commercial and industrial increased the complexity of the calculations of the baseline usage. Testing components of the baseline model provided a comprehensive understanding of the implications of customer reclassificat ion, adjustments for UG 152 volumes, weather normalization and elasticity. I believe that the overall approach employed to implement the decoupling mechanism is accomplishing what was intended.

The second portion of the review focused on testing the model, assuring the formulas were correct and that the appropriate documentation was included. The attached addendum provides a summary of the components of the model that were tested and some areas including source data that I did not validate. Overall, the model tested fine and tracked with the described methodology in the Company's documentation.

Sincerely,

Gary C. Hill
Consultant

EXHIBIT

Electric / Gas / Water

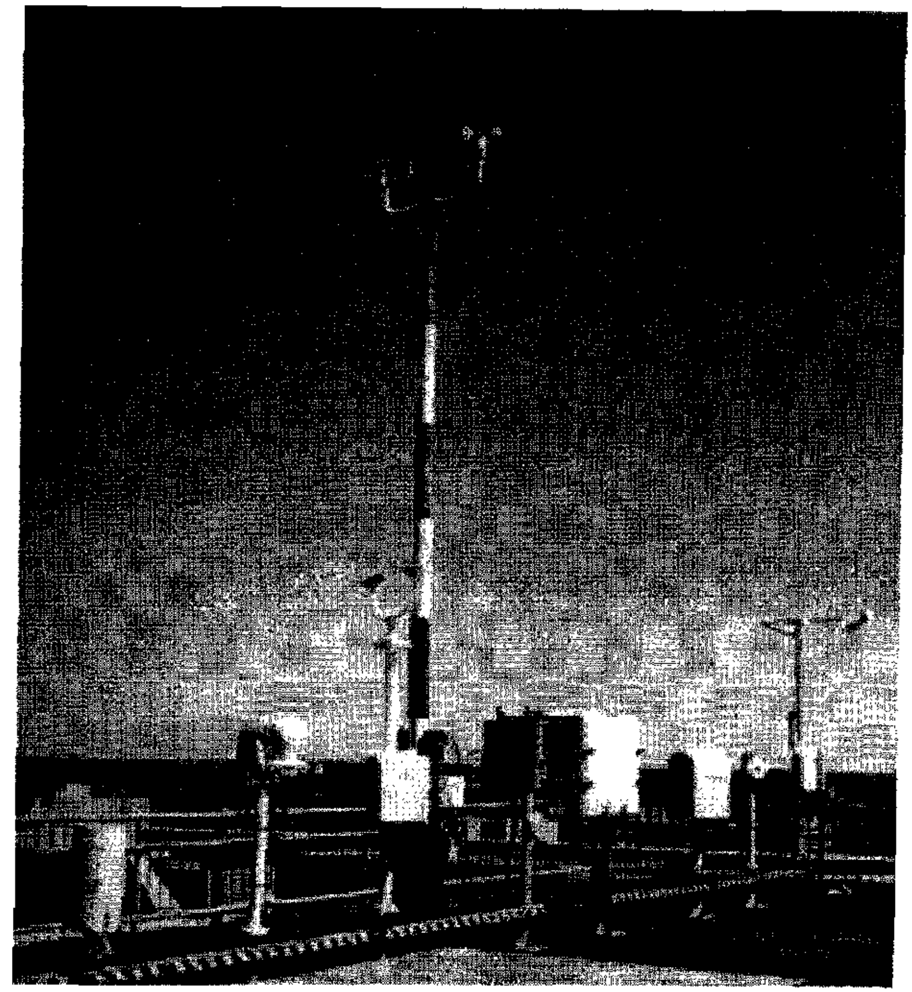
COMPANY
60

Weather Normalization

Presented by
J. Stuart McMenamin

Agenda

- Overview of Weather Normalization Concepts
- Itron Benchmarking Study
  - Uses of Normalization
  - Definition of normal weather
  - Cold weather variables
  - Hot weather variables
  - Weather adjustment methods
- Review of study results
  - Discussion of issues
  - Presentation of industry practices
  - Recommendations
- Conclusion



Applications of Normal Weather

- Financial forecasting with normal weather

– Budget forecast – usually calendar month energy use	Monthly, Averaged
– Budget forecast of daily energy (for daily tracking)	Daily, Averaged
– Monthly peak forecast	Daily, peak
– Annual peak forecast	Daily, peak

- Financial variance analysis – adjusting from actual to normal

– Adjust billed monthly energy use by class	Monthly, Averaged
– Adjust booked (calendar month) energy use by class	Monthly, Averaged
– Adjust system energy and peak demands	Daily, peak
– Adjust daily system energy to track against budget	Daily, Averaged

- Facility Planning – *weather scenario or simulations*

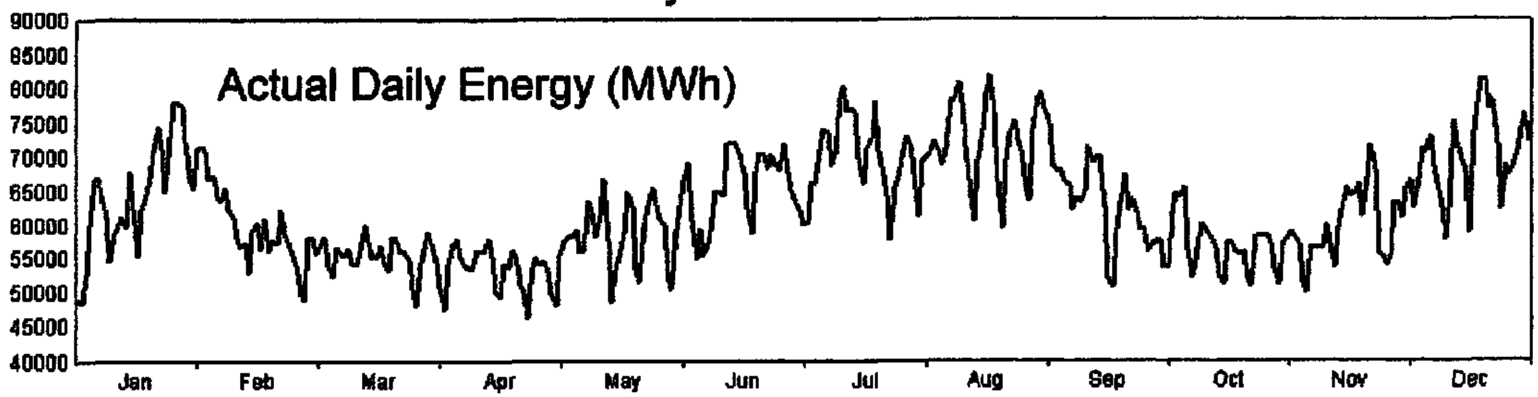
– Generate 8760 hour load forecast for dispatch simulations	Hourly, Chaotic
– Design day forecast	Daily, Extreme
– Simulate peak distributions, coincidence factor distributions,...	Daily, Multiple

- Market Analysis

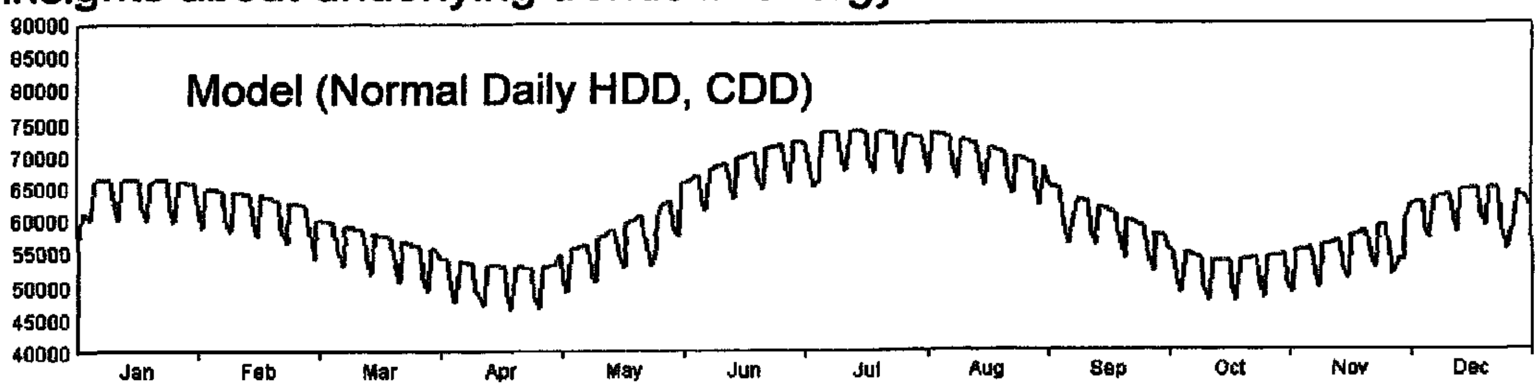
– Generate a "typical" load profile for a customer	Hourly, Chaotic
– Generate facility baselines for budgets, pricing, ...	Monthly or Daily

Why Weather Normalization is Useful

- Actual energy use is chaotic. The main source of irregularity is weather. This is most obvious at the daily level



- Models using normal weather create order out of chaos, providing insights about underlying trends in energy use and revenues.

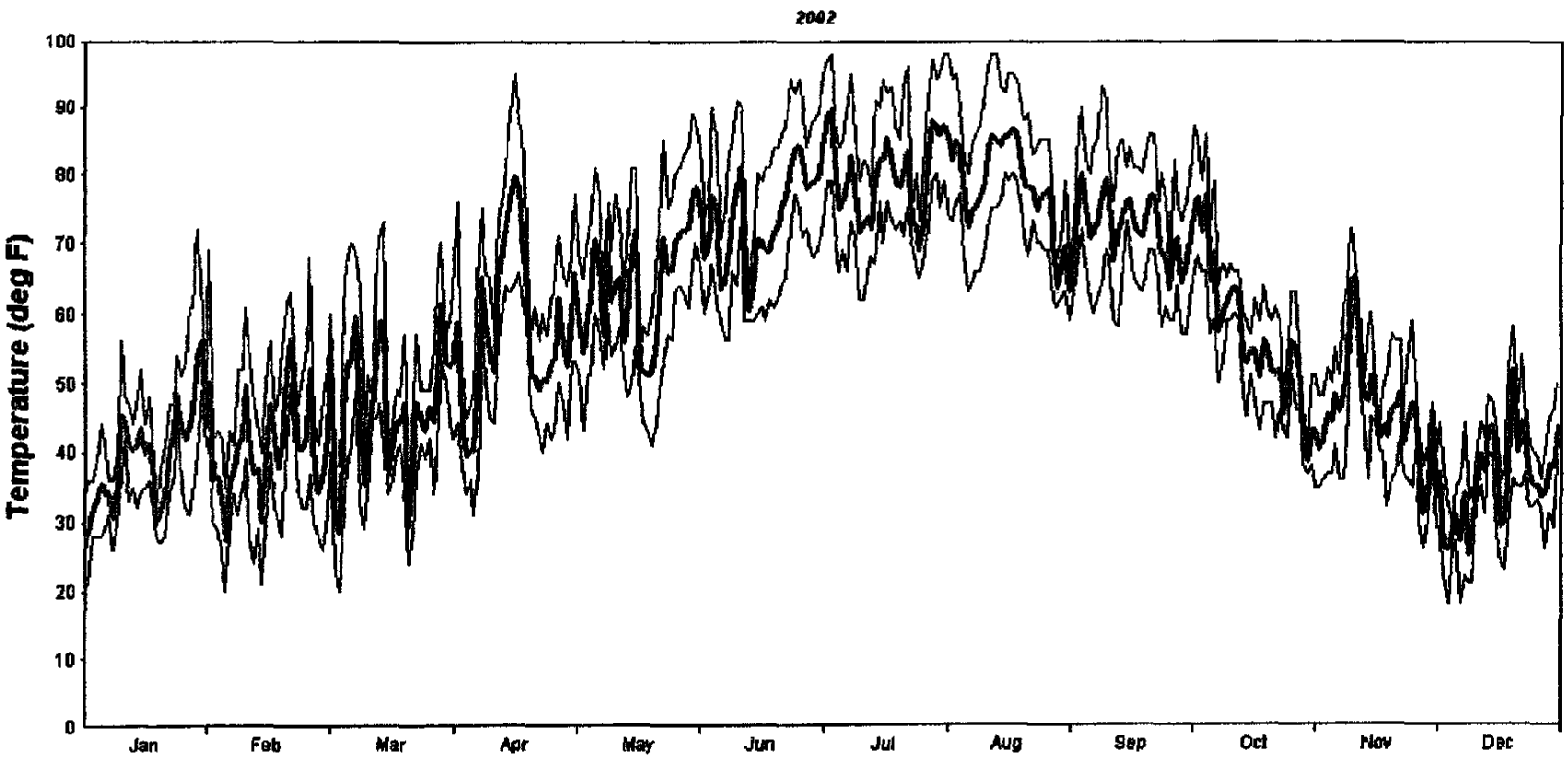


Types of Normal Weather

- Chaotic scenarios (daily or hourly)
  - Selected actual weather patterns (e.g., TMY files)
  - Rank and average, assign to calendar days. Intended to have normal extreme days as well as normal averages
- Daily Normals
  - Averaged by date
  - Apply nonlinear operations (HDD, CDD) before averaging
- Monthly Normals
  - Built up from daily normals (HDD and CDD values)
  - Average of monthly values – calendar month and/or billing month
- Peak Producing Weather
  - Weather based – hottest, coldest – normal extremes or design day (1 in 10)
  - Load based – weather on historical peak days
- Simulation Based
  - Multiple years of actual weather simulated through weather response function

Actual weather data is chaotic

- Actual weather data is chaotic. Some years are less irregular than others. But all years are irregular. So...what is normal?



Graph shows daily high, low, and average values for one year.

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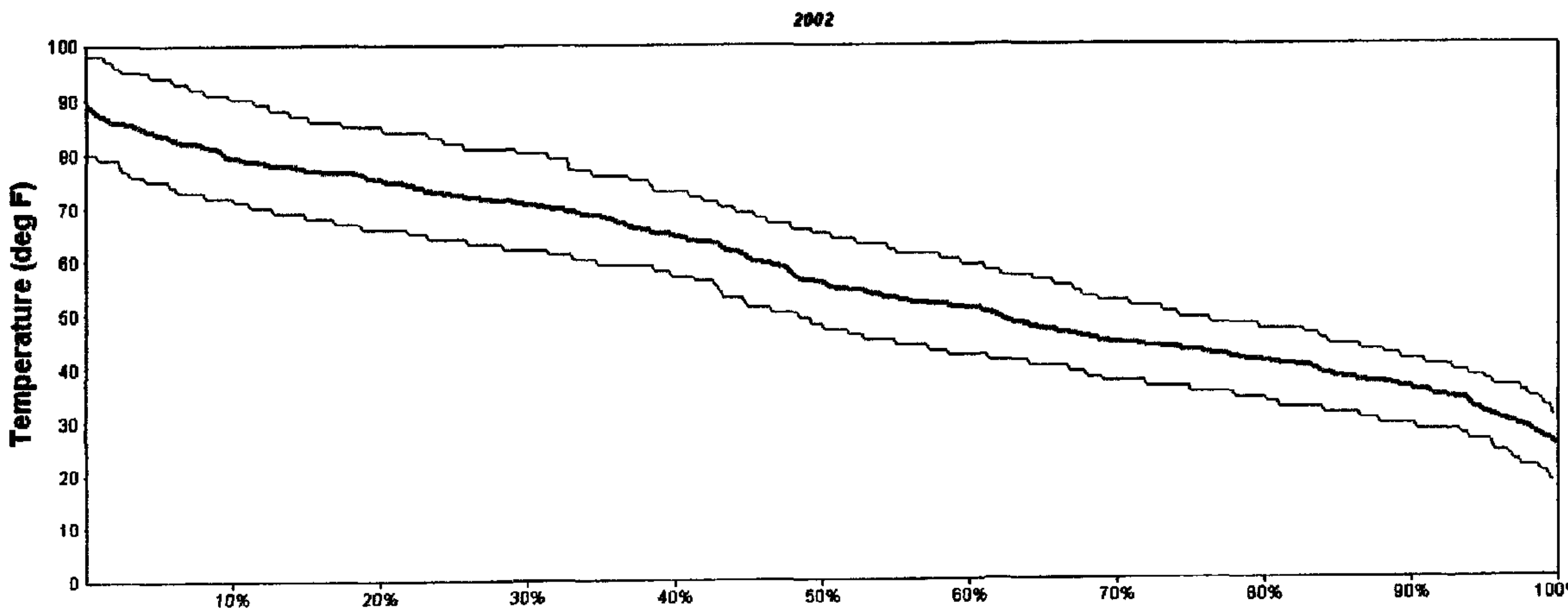
Rank and average methods

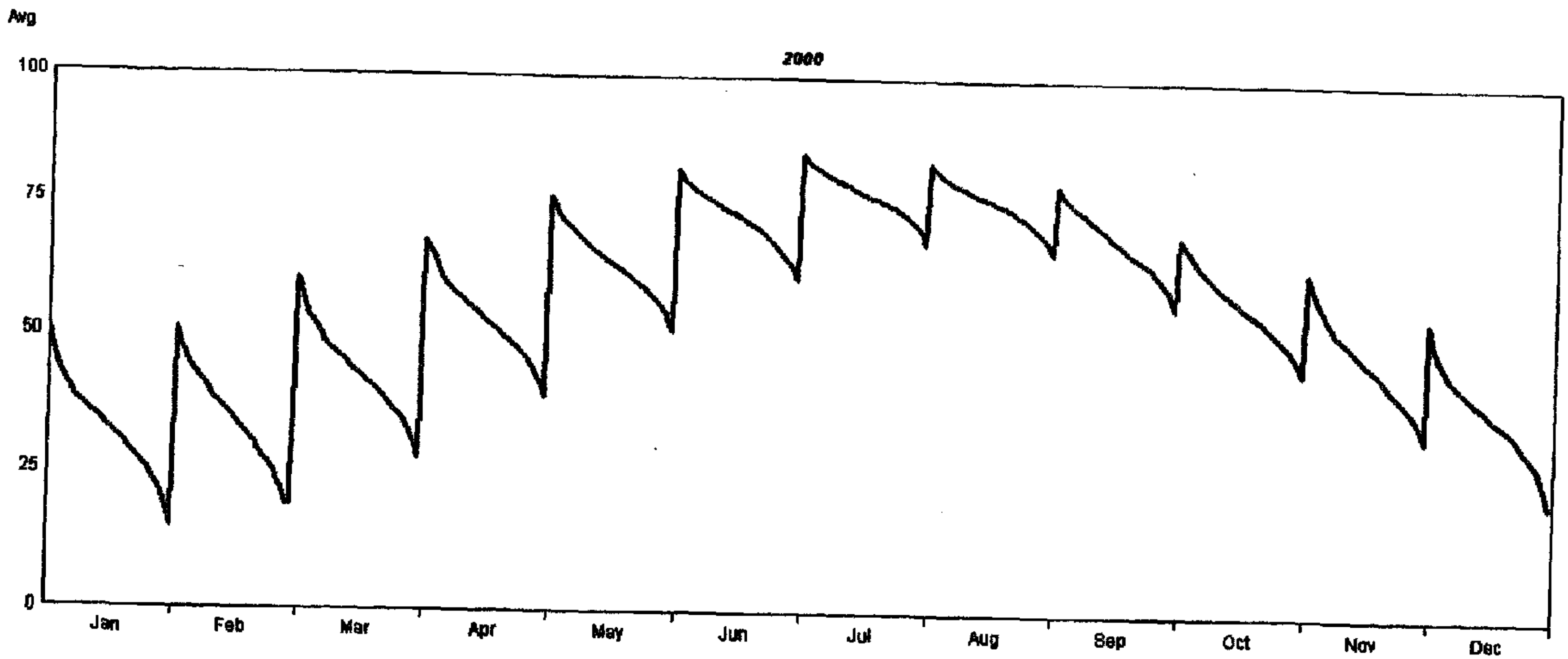
- Rank and average methods start by creating a "temperature duration" curve. The first number represents the hottest day in the year. Averaging across years gives a typical hottest day, second hottest day, ... , and on to a typical coldest day.



Graph shows sorted values for one year. High, low and average are sorted separately.

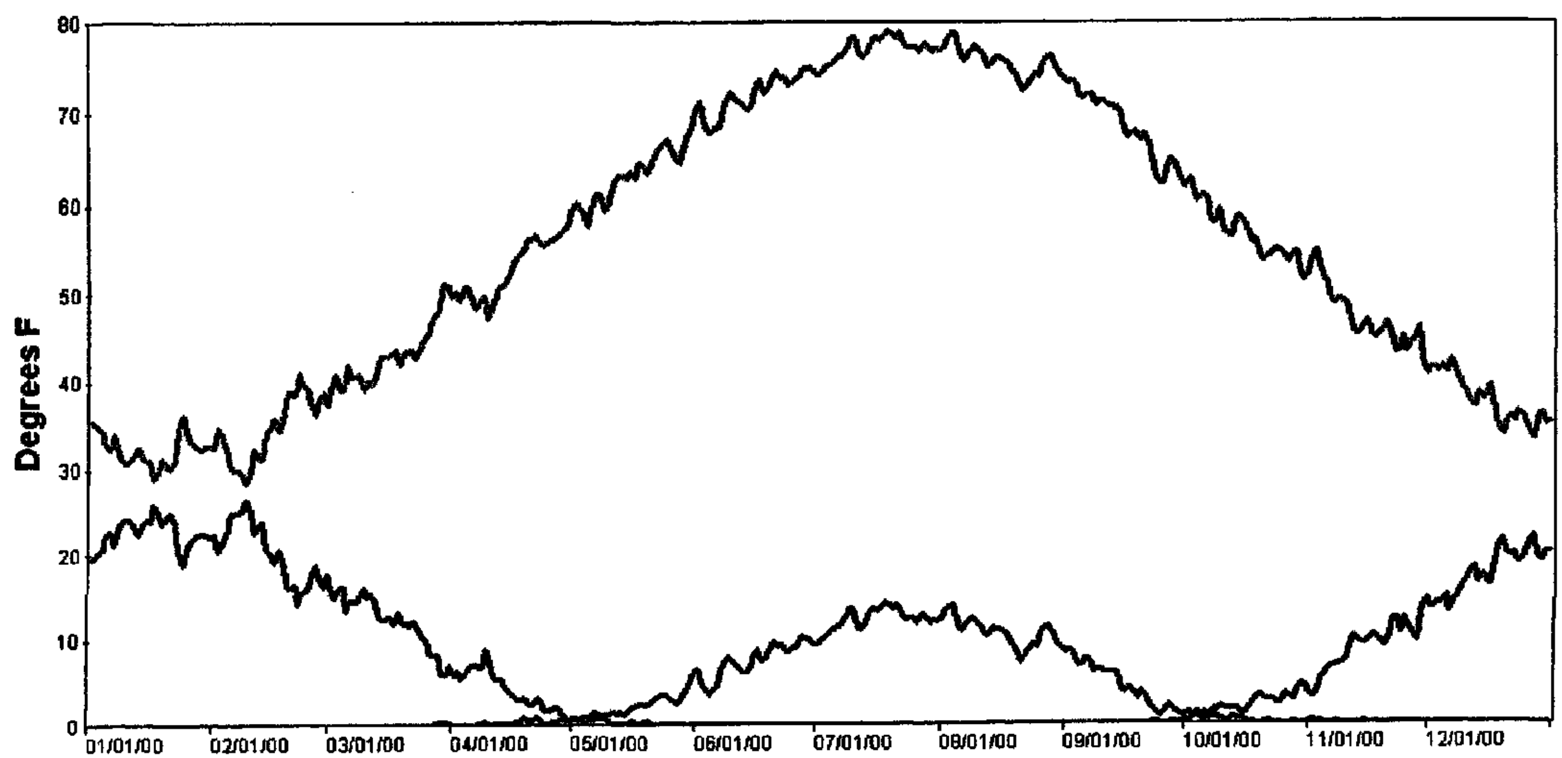
Rank and Average Methods

- Rank and average results have normal averages and normal extremes for each month (or season). They still need to be assigned out to specific dates, creating a chaotic scenario.



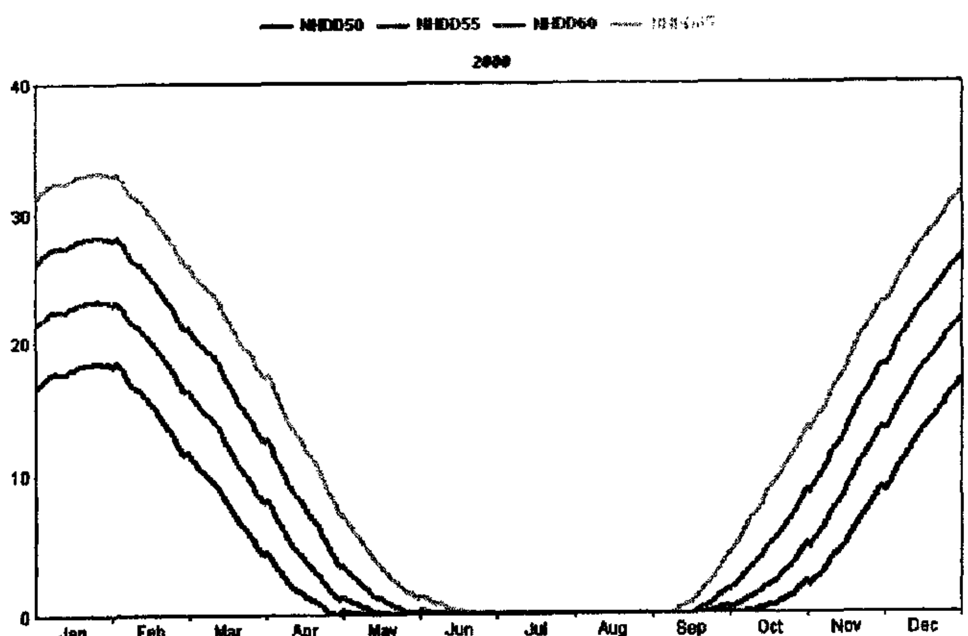
Averaging by Date

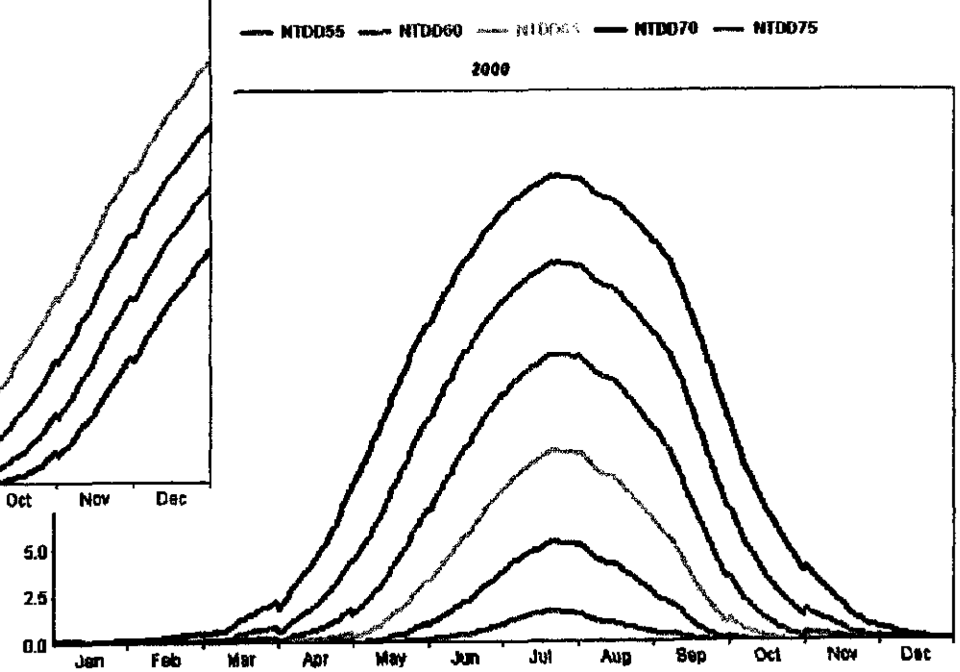
- Even after averaging across 30 years, average temperatures by date are a bit irregular. The same is true for HDD and CDD by date. Smoothing using centered moving averages will take the kinks out.



Smoothed Daily Normal HDD and CDD

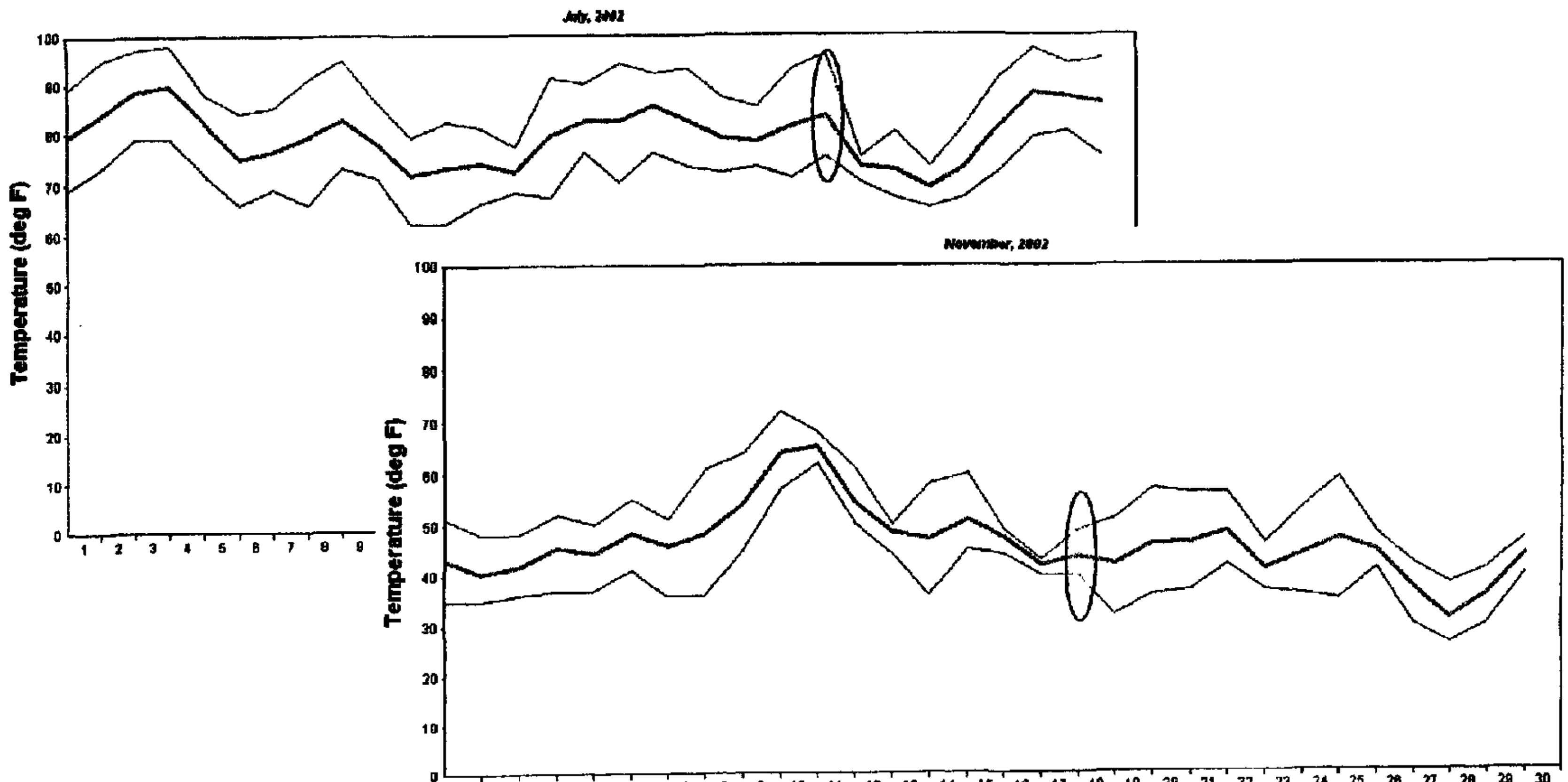
- Smoothed daily normals look like this. By constructing these values for multiple CDD and HDD cut points, it is possible to distinguish between high powered and low powered degrees in the normalization process.





Peak producing weather is multidimensional

- Peak days are not necessarily the hottest or coldest days of the year. Peak producing weather is multidimensional – temperature, humidity, wind, clouds, prior day effects, ...



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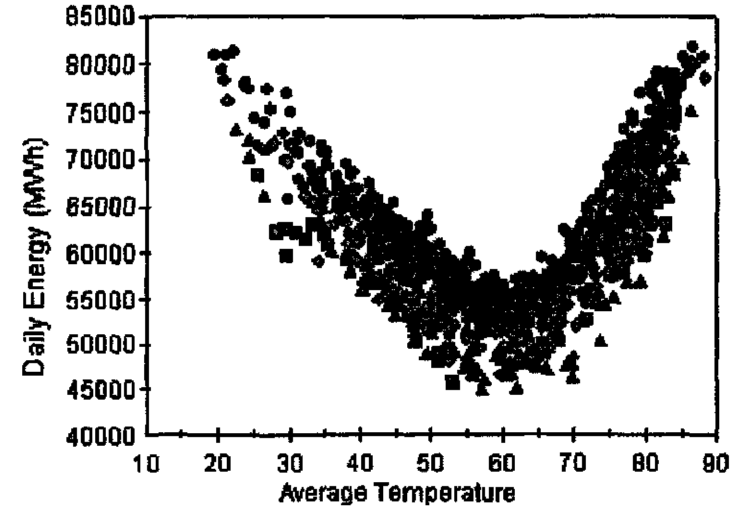
Why Weather Normalization is Tricky

- The response of energy usage to weather is not linear. As a result, averaging is dangerous. Accurate weather normalization requires nonlinear thinking.
- Weather slopes are changing rapidly in some areas.
- Weather response can differ significantly across months.



- The goal of weather normalization is to estimate the results of a simulation process with the following steps:
  - Estimate a model
  - Simulate energy use with the model for a variety of past weather patterns
  - Plot the distribution of energy outcomes
  - Compute the average of the distribution
- Conceptually we should measure our methods against this goal

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Overview of Itron Benchmarking Study

- Internet survey with about 20 questions
- 172 respondents
- 170 employ some type of weather normalization process. 2 did not employ any weather normalization process
- Distribution of respondents
  - 76% electric companies
  - 8% gas companies
  - 16% electric and gas companies

Q. What are weather normal sales used for?

- 170 responses
- Weather normalized sales are used by 73 percent of the respondents as the base for forecasting.
- 59 percent of respondents use normalization for variance analysis and 44 percent use normalization for financial reporting.
- Other uses for weather normalized sales were cited by 14 percent of respondents. These uses include:
  - support for rate filings;
  - class load studies; and
  - capacity planning.

Q. What energy concepts do you weather normalize and report?

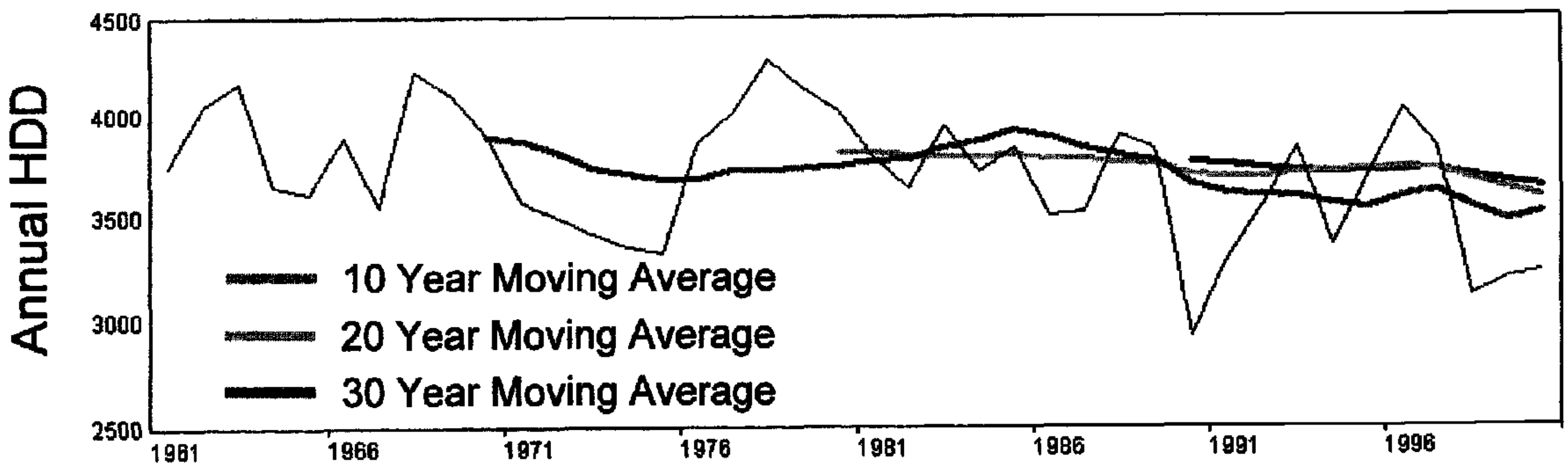
- The most common uses of weather normalization were reported to be:
  - Normalization of calendar month sales – 59 percent
  - Normalization of system peak – 54 percent
  - Normalization of billed (cycle) sales – 45 percent
  - Normalization of unbilled sales – 13 percent

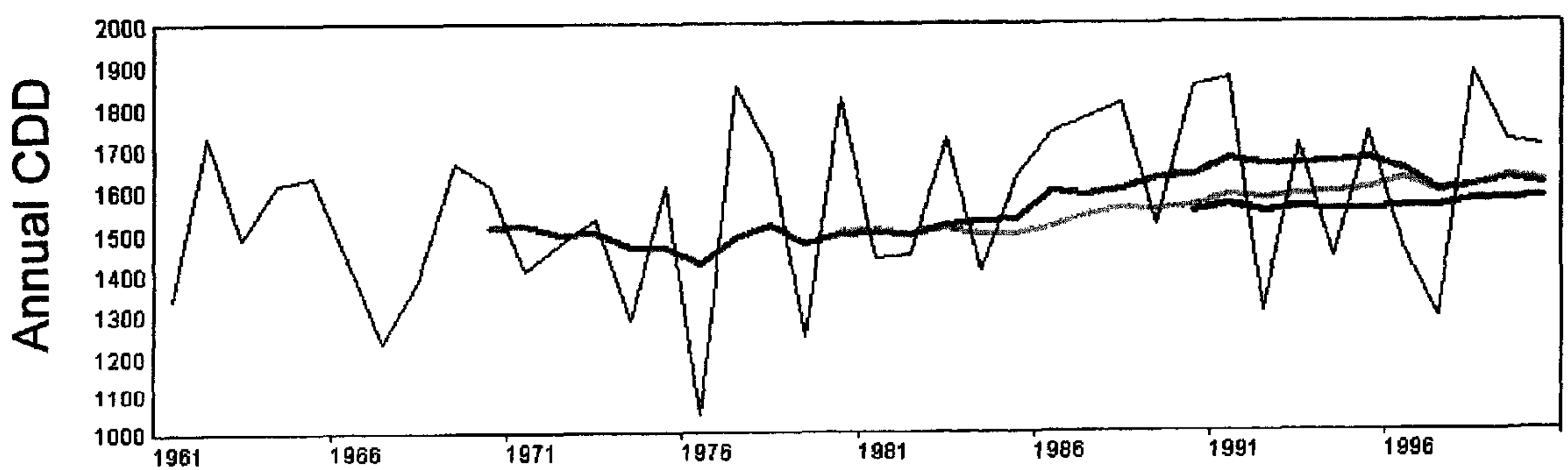
170 responses

Definition of Normal Weather

- Alternative definitions of normal weather?
  - A representative weather pattern (e.g., Typical Meteorological Year – TMY)
  - Average or median values computed from past weather patterns.
  - Typical extreme values.
- Weather variables covered
  - Temperature, humidity, wind, indexes (THI, Wind chill, ...)
- Frequency of the normal weather variables
  - Hourly, daily, monthly, annual
  - Cycle vs. calendar
- Source of the normal weather results
- Number of years of data used to calculate normal values

Trends in HDD and CDD





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Q. What do you use for normal weather?

- 167 responses
- Almost half (48 percent) of the respondents reported that they calculate normal weather using approaches developed by their company.
- The national weather services (NOAA and Environment Canada) are the source for roughly 40 percent of the respondents.
- Of this total, the vast majority use NOAA's 30-year normal weather.
- The remaining 11 percent of the respondents rely on commercial weather service providers or use typical year approaches.

Q. How many years of data do you use?

- 106 responses
- The majority (71 percent) of the respondents use 20 or more years to define normal weather.
  - Thirty years of data are used by 43 percent of the respondents.
  - Twenty years of data are used by 17 percent of the respondents.
  - Twenty-five years (2 percent) and
  - more than thirty years (9 percent) make up the balance of this majority.
- 6 percent of the respondents use 15 years of data.
- 16 percent use 10 years of data.
- Seven percent of the respondents use less than 10 years and most of those are using five years.
- The longest time span of data used is 60 years. The shortest span of data used is one year.

Q. Do you calculate an updated set of normal values every year?

- 114 responses
- Over two-thirds of the respondents (69 percent) update their normal values on a yearly basis
- The remaining 21 percent do not update their normal values annually

Q. Has the number of years that you use to define normal weather changed in the last few years?

- 115 responses
- Most respondents (75 percent) report that they have not changed their definition of normal weather.
- Of those that have changed the definition of normal years, the movement is, on average, to use a shorter data range.
- One of the reasons cited for change is that the 30-year normal is no longer relevant or does not reflect recent weather trends.
- Some cited the need to account for global warming as the reason behind moving toward a shorter time span.

Definition of Weather Variables

- Heating Degree Day Variables
  - HD = heating degrees = degrees below a base temperature

    HD = Max(55-AvgTemp, 0)

    Example: AvgTemp = 43 implies HD = 12
  - HDD = heating degree days = Sum of HD over days in a cycle or month
- Cooling Degree Day Variables
  - CD = cooling degrees = degrees above a base temperature

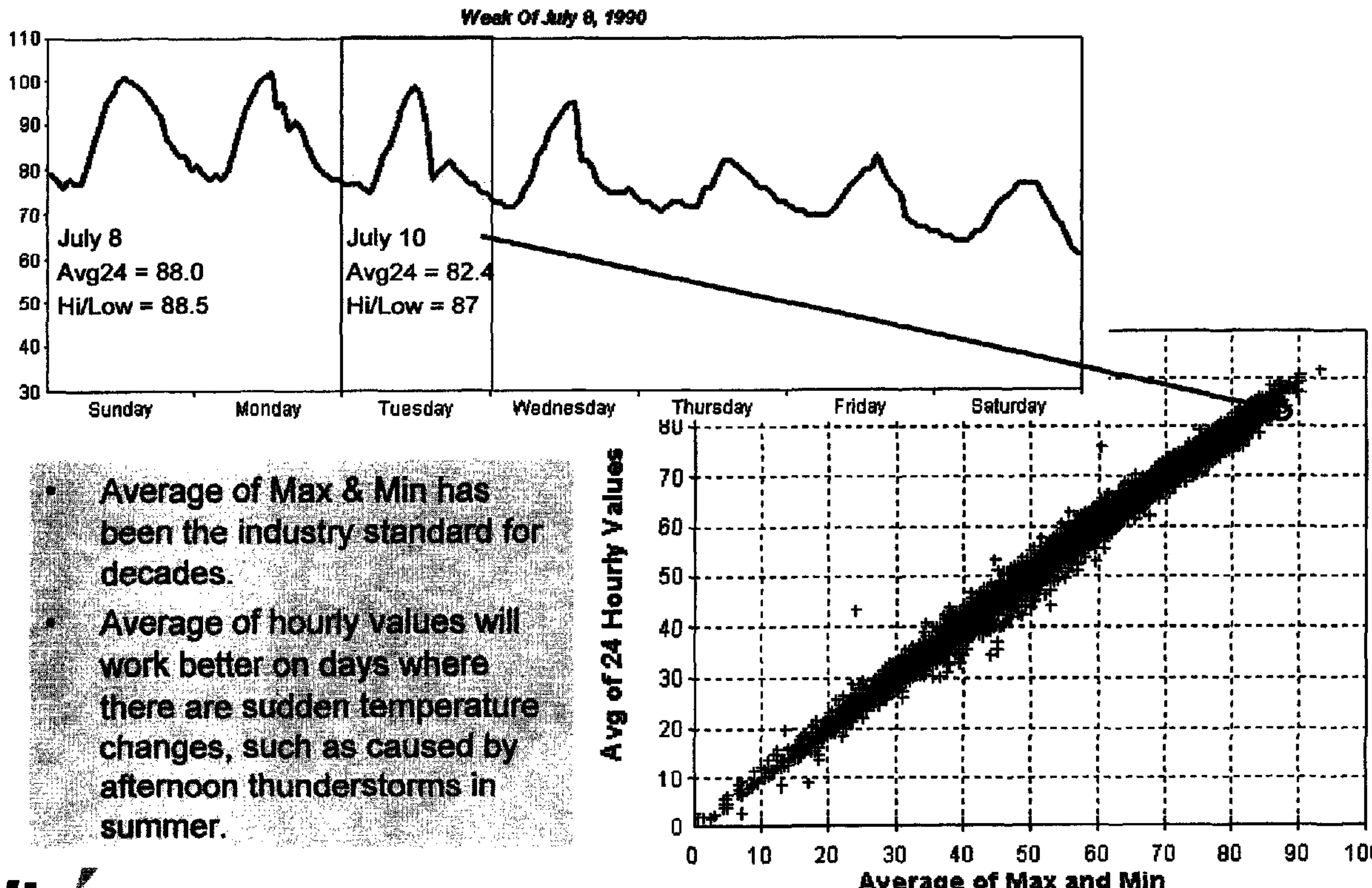
    CD = Max(AvgTemp – 65, 0)

    Example: AvgTemp = 77 implies CD = 12
  - CDD = cooling degree days = Sum of CD over days in a cycle or month
- Issues:
  - Definition of average temperature
  - Inclusion of other factors (humidity, wind)
  - Base temperature value(s)

Q. If you use HDD and/or CDD that are calculated using a daily average temperature, how do you calculate the daily average temperature?

- 137 responses
- The majority (60 percent) of respondents compute average daily temperature as the average of the daily maximum and minimum temperatures.
- The average daily temperature is computed using an average of the 24-hour temperature values by 19 percent of the respondents.
- Seventeen percent use the average daily temperature provided by their weather service provider.
- The remaining 4 percent of the respondents use some form of THI or weighting of multiple days.

Example of Averaging Methods



- Average of Max & Min has been the industry standard for decades.
- Average of hourly values will work better on days where there are sudden temperature changes, such as caused by afternoon thunderstorms in summer.

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Calculation Logistics for Daily Normals

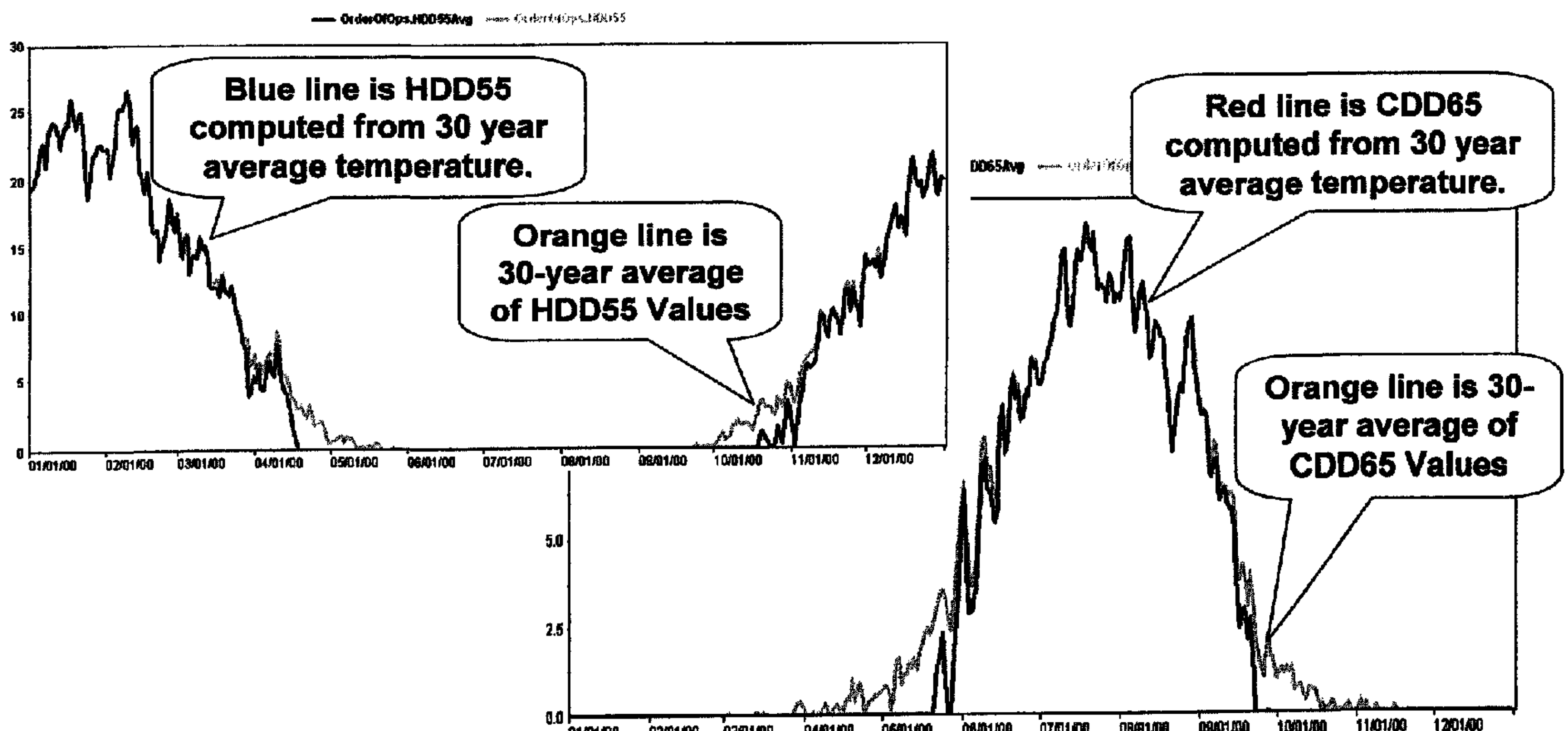
- Daily normals
  - NOAA has a daily normal series for HDD, CDD
  - Values are computed from 30 years and smoothed
  - DD values are computed for each date, then averaged across years
- The Rule: Always apply nonlinear operations first, then average. An example of the rule follows.

	Temp	CDD60	CDD65	CDD70
Year1	60	0	0	0
Year2	65	5	0	0
Year3	70	10	5	0
Year4	75	15	10	5
Year5	80	20	15	10
Avgerage	70	10	6	3

- A generalization of the rule is that we should compute predicted load with each historical weather pattern (a nonlinear transformation of weather) and then average the predicted loads.

Order of Operations Matters

- The order of operations matters. Compute nonlinear transformations (HDD and CDD) first, then average over years. Computing HDD and CDD from averaged values will cause a downward bias in swing months.



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Calculation Logistics for Monthly Normals

- Computed from Daily normals
  - Aggregate daily normal values by cycle
  - Average across cycles
  - Resulting normal monthly values reflect cycle schedules

- Computed from Monthly actuals
  - Compute DD variables for each historical month
  - Average across years for each month
  - Could also adjust for cycle days

- Calendar Month normals computed either way are about the same. The only fly in the ointment is Feb 29.

- Special calculations are required for peak producing weather.

Q. What variables do you use to adjust for cold weather?

- 166 responses

- The vast majority (80 percent) of the respondents report using Heating Degree Day (HDD) values based on temperature data.

- THI based HDD variables are used by 4 percent of the respondents.

- The remaining 16 percent of the respondents adjusted for temperature, humidity, cloud cover, and/or wind speed.

Q. If you use HDD, do you use a single base temperature or multiple segments?

- 86 responses
- The majority (85 percent) of the respondents report using a single trigger point.
- For companies using the Celsius scale, the average trigger point is 18°.
- The most commonly reported trigger points on a Fahrenheit scale are 55° and 65°.

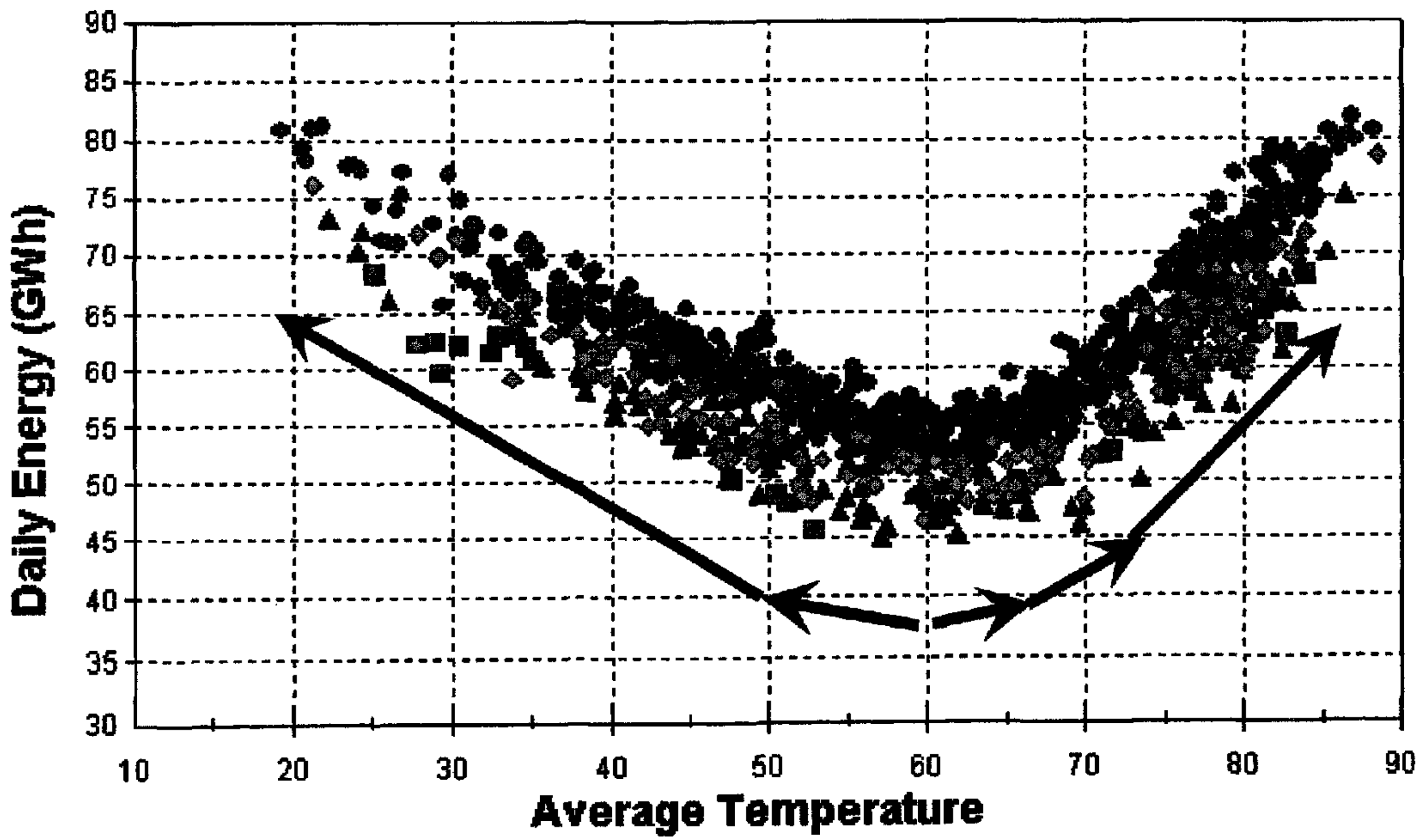
Q. What variables do you use to adjust for hot weather?

- 158 responses
- Roughly two-thirds (69 percent) of the respondents are using temperature data only to adjust for hot weather.
- Eight percent of the respondents use THI.
- The remaining 23 percent of the respondents report either that no adjustment is required for hot weather because they operate in climates with little to no cooling loads; or that they account for temperatures, humidity, cloud cover, and/or windspeed.

Q. If you use CDD, do you use a single trigger temperature or multiple segments?

- 123 responses
- Similar to the response for HDD, the vast majority (85 percent) use a single trigger point temperature for CDD.
- The typical trigger point is 18° Celsius or 65° Fahrenheit.
- For the respondents that use multiple trigger points, the trigger points that are used to separate cooling loads are between 65° F and 75° F and cooling loads above 75° F.

Example of Multiple Segments for HDD and CDD



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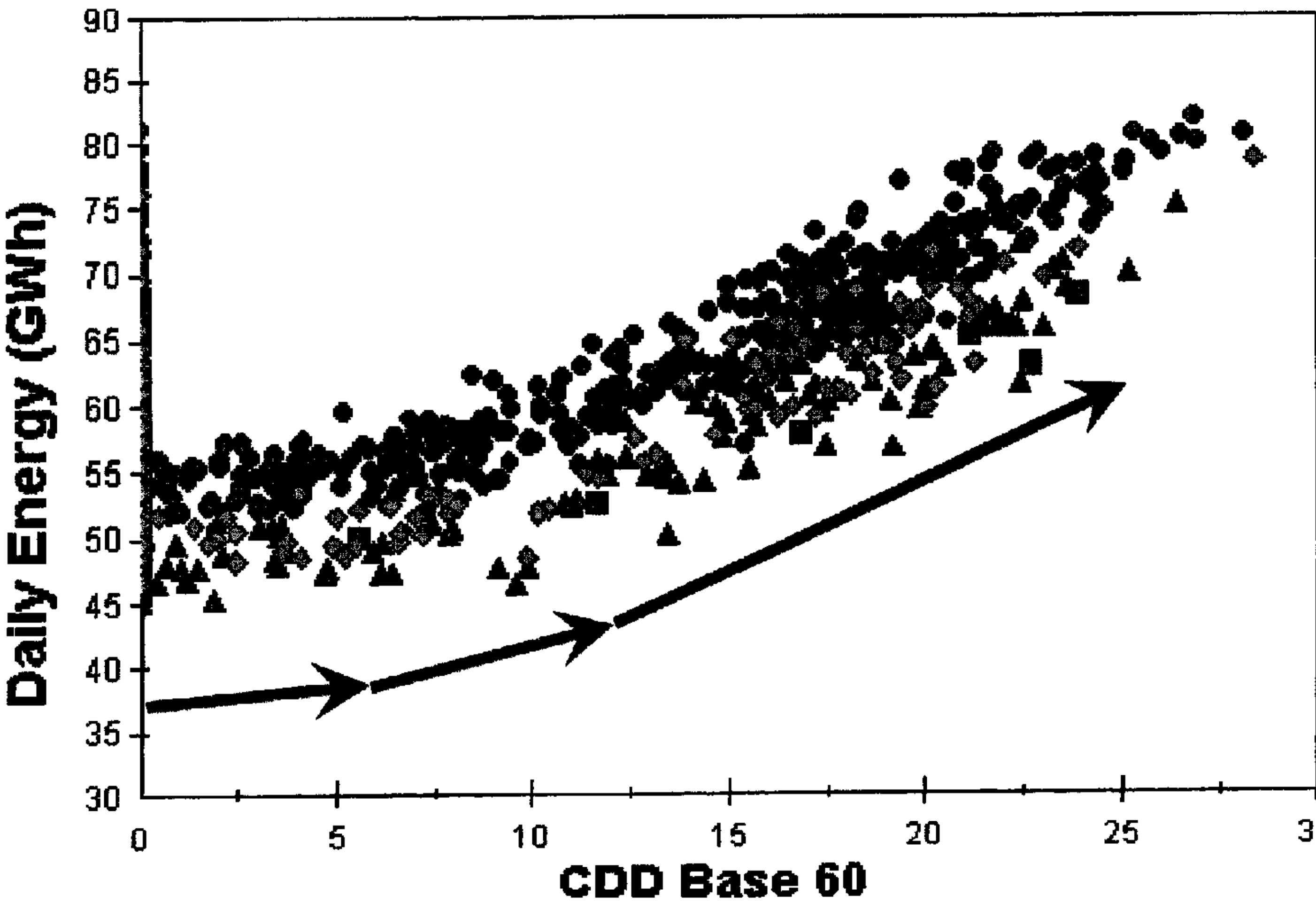
Example as a Regression Model Sees the Data



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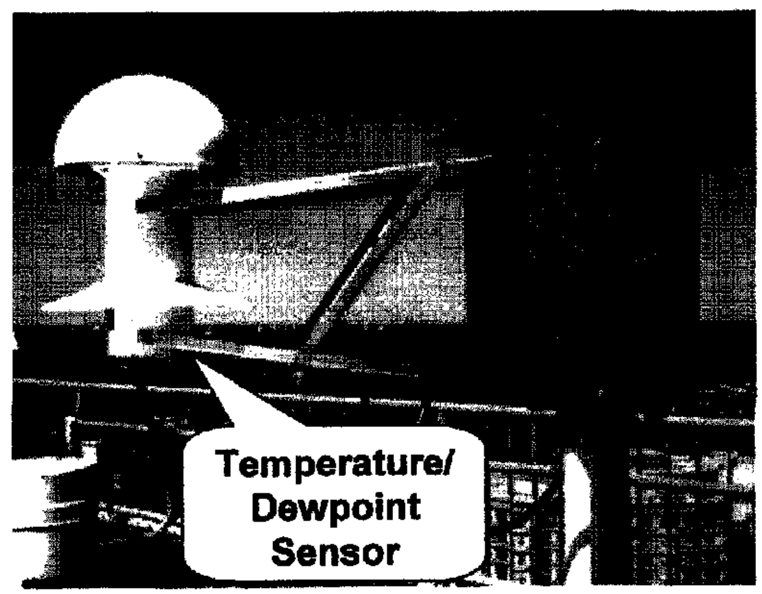
Q. If HDD and/or CDD are calculated using THI, which formula do you use to define THI?

- 108 responses
- (26 percent) THI = 15 + 0.4 x (DryBulb + WetBulb)
- (32 percent) THI = 17.5 + 0.2 x DewPoint + 0.55 x Drybulb
- (16 percent) THI = Drybulb - (0.55 x (1 - Humidity)) x (Drybulb - 58)
- (26 percent) Other



Q. How do you compute weather normalized sales?

- 159 responses
- The majority (60 percent) use weather adjustment coefficients to normalize sales.
- Thirty percent use model simulations.
- The remaining 10 percent use some other process to normalize sales.

Model Approach

Wthr Adj = F(Normal Weather) – F(Actual Weather)

Coefficient Approach

Wthr Adj = b*(Normal Weather – Actual Weather)

Q. How often do you update your weather normalization coefficients or models?

- 163 responses
- The majority (52 percent) update coefficients once a year.
- Monthly updates are generated by 13 percent of the respondents and quarterly updates by 3 percent of the respondents.
- The remaining 31 percent of the respondents update coefficients every few years or in response to a rate case.

Q. Do you also re-calculate historical weather normal sales when you update your weather coefficients or models?

- 158 responses

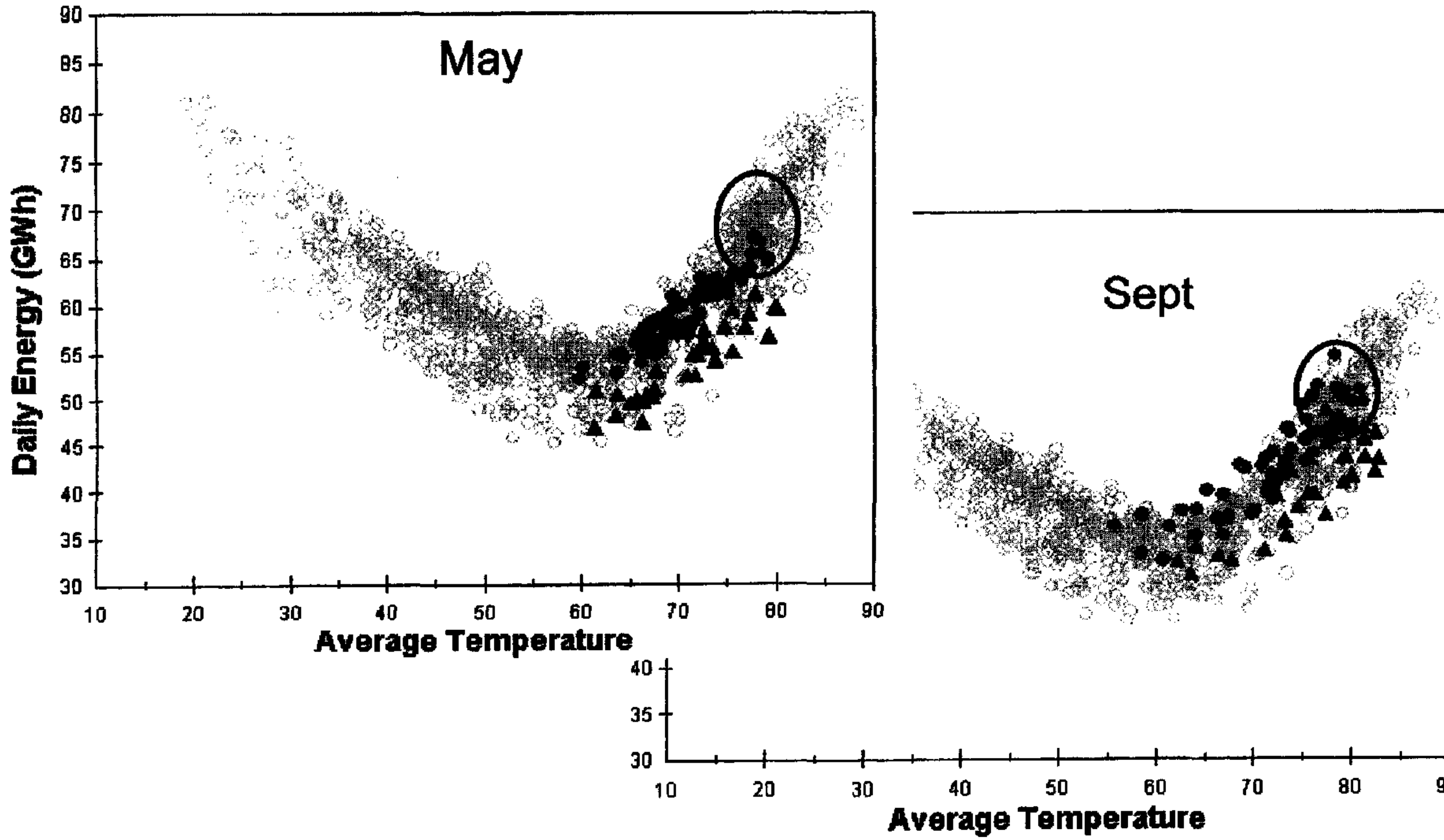
- The majority (56 percent) of respondents do not re-calculate historical weather normal sales when they update their weather coefficients or models.

- Forty-four percent do re-calculate.

Q. Do weather adjustment parameters vary by month or season?

- 162 responses
- The majority of the respondents (66 percent) report that the weather adjustment parameters are allowed to vary either by month (45 percent) or by season (21 percent).
- Another 27 percent indicate that the parameters do not vary. Those that indicate some other method report that, for the most part, the parameters are allowed to vary although not necessarily by month or season.

Example of Weather Data by Month



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Q. Is the weather normalization process that you use specified by your state commission?

- 166 responses
- Roughly 13 percent of respondents use a commission specified normalization process.
- Eighty-seven percent cited that they use their own weather normalization process.

Q. In statistical models of class sales (e.g., residential, commercial, industrial) which do you use?

- 158 responses
- Calendar-month HDD and CDD variables are used by 40 percent of the respondents.
- An additional 12 percent use calendar-month HDD and CDD variables with weights on current and previous months.
- Billing-cycle weighted HDD and CDD variables are used by 32 percent of the respondents.
- The remaining respondents use some form of lining up the HDD and CDD data with the sales data that is being modeled. Others indicated using the system load as a means of weighting the weather data.

Q. Is the approach you use for normalizing energy the same as what is used for developing normalized peaks?

- 159 responses
- The same approach was used to normalize energy and peaks by 42 percent of the respondents.
- The majority of the respondents (57 percent) indicate that they use different approaches.
- A small fraction of respondents indicate that they do not normalize peaks.

EXHIBIT

COMPANY
61

A Statistical Evaluation of the Predictive Abilities of Climatic Averages

KEITH W. DIXON AND MARK D. SHULMAN

Department of Meteorology and Physical Oceanography, Cook College—New Jersey Agricultural Experiment Station, Rutgers—The State University of New Jersey, New Brunswick, NJ 08903

(Manuscript received 6 April 1983, in final form 5 August 1984)

ABSTRACT

The predictive abilities of NOAA normals and running means of 2–30 years length are tested statistically. Heating degree-day (HDD) data from six northern United States sites are tested using root-mean-square error of prediction (RMSE) tests, mean absolute error (MAE) tests, and a "best versus worst" predictor methodology. Monte Carlo tests using biased and unbiased numbers are presented for the RMSE and "best versus worst" analyses. Results are consistent with past research in showing that running means 10–30 years in length perform better than shorter averaging periods for predictive purposes. The MAE values are generally found to be lowest for running mean lengths shorter than that for the RMSE statistic at the six sites. For the 30 years studied, NOAA HDD normals performed well along the east coast, indicating a possible regional difference that requires more detailed investigation. Limitations of the "best versus worst" predictor method are discussed, and it is suggested that such a procedure should not be solely relied on in determining the optimum length of prediction.

1. Introduction

In the middle 1970s, as the era of relatively low cost petroleum fuels quickly came to an end, public interest concerning fuel usage, conservation and price structure increased. The winters of the late seventies, which brought extreme cold to many parts of the United States, revealed just how much of an economic burden heating homes could be for consumers when unusually severe winters are coupled with high fuel prices. The meteorological parameter which is best related to heating fuel usage is the heating degree-day (HDD).

As one might expect, as energy prices rose so did the interest expressed by consumer groups and utility companies concerning how the "normal" climate was defined, with respect to HDDs. Thus, the traditional 30-year normal used by the National Oceanic and Atmospheric Administration (NOAA) and the World Meteorological Organization, and the justification for its use, came under scrutiny.

The questioning of the definition and applicability of climatic normals is not a new development. Articles published in the 1930s and 1940s raised the very same questions as those now being debated, although attempts at rigorous statistical testing were not generally attempted until the 1950s. Examples of the earlier discussion of climatic normals include those of Gisborne (1935), Mindling (1940) and Landsberg (1947).

When attempting to determine the normal length that is best at estimating future values, a question which must be addressed is What criterion should be used to select the optimum length of record? Previous researchers have used various methods and statistics in their studies. However, what they all have in common is that running arithmetic means ($\bar{X}_{j-1,n}$) of varying length n, ending with year $j-1$, are used to predict the jth year's value (X_j). The smaller the error E, where $E = [(X_j) - (\bar{X}_{j-1,n})]$, the better the prediction. The number of comparisons possible (m) for each value of n is determined by the length of the entire data record (L) and the maximum running mean length to be tested (n max). The relationship is given by the equation $m = L - (n \text{ max})$. The most popular statistic used to test the predictive abilities of running means has been the root mean square error (RMSE), or a similar statistic, such as the mean square error (MSE). The RMSE for a given n value is given by the equation:

$$\text{RMSE} = \{1/m \sum^{m} [X_j - (\bar{X}_{j-1,n})]^2\}^{1/2} \quad (1a)$$

or

$$\text{RMSE} = 1/m(\sum^{m} E^2)^{1/2} \quad (1b)$$

and

$$\text{MSE} = (\text{RMSE})^2. \quad (1c)$$

In studying various climatological and hydrological parameters, Beaumont (1957), Enger (1959), Lamb and Changnon (1981) and Shulman and Dixon (1983) have reported lowest RMSE or MSE values for running means of 15–30 years in length. Court (1967–68) reported that running means of 10–40 years gave about the same predictive accuracy when tested using the MSE statistic. Court's review of Monte Carlo tests suggested that for many climatic records of annual temperature, progressive changes in the mean exist. These changes, whether caused by true climatic fluctuations or by observational or instrumental changes, reduce the optimum length of record to values less than that which would be expected from a totally unbiased random number series. Court also stated that stations in the same vicinity tended to yield similar results when tested with the MSE statistic.

Another measure which has been used to test the ability of various means to predict future values of a climatological parameter is the mean absolute error (MAE), which is given by the equation:

$$\mathrm{MAE} = (1/m) \sum^{m} |[(X_j - (\bar{X}_{j-1,n})]| \qquad (2a)$$

or

$$\mathrm{MAE} = (1/m) \sum^{m} |E|. \qquad (2b)$$

The MAE is simply the average of the absolute errors for the m comparisons made for each value of n.

Court reported that while the plotted MAE statistic versus the length of record reaches its asymptote more quickly than the MSE statistic, the two yielded similar results.

The MAE and the RMSE differ in that the RMSE is a function of the square of the errors, not simply the mean of their magnitude. Since it is often not only desirable to choose a predictor which over the long run will give a low average error, but of extreme importance to minimize the number of large errors, the RMSE statistic has been more popular than the MAE in past studies.

In 1981 Lamb and Changnon (hereinafter LC) introduced another method designed to determine the optimum length of record. This "best predictor" method merely noted which length of record n, ending with a given year j, produced the prediction closest to the actual value for the year $j + 1$ for each of the m comparisons.

This method has some limitations that were not addressed at the time. First, most of the information generated in the computation and testing of the various running means was not used to compute this new summary statistic. Only six values of n (5, 10, 15, 20, 25 and 30) were tested using this analysis technique. Thus, only one-sixth of the errors computed were presented, those being the smallest error for each of the m comparisons made. Whether the second best predictor was 1% or 100% worse than the best was not noted; nor was which n produced the second best prediction, or the third best, or the worst prediction, etc., taken into consideration.

When applying this method, we note that the m individual best predictions must be distributed among the number of n-values tested. Therefore, a trade-off exists between the number of n-values that may be tested and the interpretability of the results.

In their summary, LC reported that "five-year normals were found to most frequently provide the closest estimate of the next year's . . . winter mean temperature . . ." and thereby met their criterion to be ". . . considered the best for characterizing the recent climate for a given point in time and assessing the abnormality of the next year." Lamb and Changnon also noted that differences in conclusions drawn from results of RMSE or MAE tests and the best predictor method exist because ". . . five-year normals tend to possess larger prediction errors when they are not the best predictors, than do other normals." Prediction errors were also "very large" when five-year normals were the best temperature predictors.

However, since short record lengths, such as five-year averages, tend to have larger standard deviations than longer term averages, it follows that short-term averages are also likely to produce the "worst" prediction most often (defining the n year average which was farthest away from the actual value as being the worst predictor).

Results of tests which follow the methodology of LC in determining the best predictor are included in this paper, as well as the results of the worst predictor tests that follow from this analysis technique.

2. Procedure

a. Data employed

Monthly temperature and HDD data were obtained for the 60 winters in the period 1920–21 through 1979–80 for the six station locations listed in Table 1. Northern United States sites with sufficiently long data records and relatively minor instrument relocations were selected. Complete HDD records were available for three of the stations. For the remaining locations, data were reconstructed for winters with missing data.

Sixty years worth of data were gathered since it was decided to test running means of length $n = 2$ to 30 years inclusive. Since three sets of 30-year

TABLE 1. Location of stations used in the statistical evaluation.

Station	Latitude (N)	Longitude (W)
Cario, Illinois	37°00′	89°10′
Cincinnati, Ohio Abbe Observatory	39°09′	84°31′
Marquette, Michigan City Office	46°34′	87°24′
New York City, New York Central Park Observatory	40°47′	73°58′
Parkersburg, West Virginia	39°16′	81°34′
Trenton, New Jersey	40°13′	74°46′

normals had been issued by NOAA (each valid for a decade), m (the number of comparisons possible) equals 30. The normals were used such that the normal based on the period 1920–21 to 1949–50 was used as the predictor for the ten winters from 1950–51 through 1959–60, and so on. Given $m = 30$ and n max = 30, L must then equal 60 years.

b. Twelve month HDD—monthly temperature relationships

In the United States, HDDs are computed on a daily basis, using the equation

$$\mathrm{HDD} = 65 - \bar{T},$$

where $\bar{T}$ is the daily mean temperature measured in degrees Fahrenheit. It follows that winter monthly temperatures should be strongly related to 12-month HDD totals. To determine the magnitude of this relationship, linear correlations of HDD totals and winter temperatures were computed in this study for each of the six locations for the last 30 years. This was done to determine how well HDD totals could be approximated by monthly temperature sums, since many stations have longer temperature records than HDD records.

In computing these correlations we note three ways of defining winter temperature; namely, the sum of the three monthly mean temperature December–February, the sum of the five mean monthly temperatures November–March and the sum of all months with mean monthly temperatures below 50 degrees Fahrenheit. The R-squared statistics are found in Table 2, as are the increases in the percentage of explained variance of the longer period averages compared to the three-month cumulative temperatures.

Reconstructions for the period 1920/21–1928/29 were made for the Marquette and Cairo stations using least-squares regression equations derived during the procedure which produced Table 2.

The method of reduction to standard series (Brooks and Carruthers, 1935) was used to reconstruct HDD data for the NYC Central Park location from the NYC Battery Park station data. During the 24 year overlap period, Central Park averaged 50 or more HDDs per 12 month period than the Battery Park station. The relationship, Central Park = Battery Park + 50, was used in the reconstruction of the 10 missing HDD totals.

The reduction to standard series was also used to reconstruct 1978–79 HDD data at Marquette. Eighteen years of overlap between Marquette and Chatham Experimental Farm data produced the equation: Marquette = Chatham − 271 HDDs, which was used to estimate the missing value.

c. Testing of heating degree-day normals

Computer programs were run, using the 60 years of HDD totals of each of the six stations as input, which computed the RMSE and MAE statistics for running means of length 2–30 years, as well as for the NOAA normals. The lower the RMSE, or MAE value, the better the predictive ability. For the reasons listed earlier, the RMSE will be discussed and relied on more than the other statistics exhibited in seeking to determine the optimum predictor of HDD totals.

TABLE 2. Correlation between seasonal heating degree days (July–June) and cumulative winter temperatures of varying lengths for the period 1950/51 through 1979/80.

Location	Months	R	RSQ	Explained variance increase (%)
Cairo, IL mean HDD = 3909	Dec.–Feb.	−0.815	0.664	
	Nov.–Mar.*	−0.954	0.911	24.7
Cincinnati, OH (Abbe) mean HDD = 4949	Dec.–Feb.	−0.862	0.743	
	Nov.–Mar.*	−0.939	0.882	13.9
Marquette, MI† mean HDD = 8411	Dec.–Feb.	−0.685	0.469	
	Nov.–Mar.	−0.835	0.697	22.8
	Oct.–May*	−0.942	0.887	41.8
New York City, NY (Central Park) mean HDD = 4857	Dec.–Feb.	−0.846	0.715	
	Nov.–Mar.*	−0.927	0.859	14.4
Parkersburg, WV mean HDD = 4920	Dec.–Feb.	−0.916	0.840	
	Nov.–Mar.*	−0.946	0.896	5.6
Trenton, NJ mean HDD = 4965	Dec.–Feb.	−0.863	0.744	
	Nov.–Mar.*	−0.927	0.860	11.6

* Indicates that the period coincides with all months with mean monthly temperatures of <50°F.

† For Marquette, Mich., a 28-year period was used in computing the correlations (1950/51 through 1977/78) due to a discontinuous record as of Jan., 1979.

A procedure designed to investigate the questions raised concerning the methodology of LC in testing for the best predictor, was run for each station. The best predictor of a given HDD total was defined exactly as in the LC study; namely, that n-value (5, 10, 15, 20, 25, or 30) which produced the prediction closest to the observed value for each of the m years tested. This analysis was taken one step further by defining the predictor that was most often the farthest from the actual value as being the worst predictor.

Two Monte Carlo simulations were performed to yield more information concerning the characteristics inherent to the best versus worst methodology. The first Monte Carlo simulation consisted in executing the best versus worst analysis on 3000 separate data records of 100 random numbers. The random numbers had a mean of 5000 and a standard deviation of 375 (values typical of HDD data records for many regions of the United States). Since n max = 30 and L = 100, the number of comparisons (m) made per trial equaled 70 for each of the 3000 trials. Therefore, over the six n-values tested, 210 000 "best" and a like number of "worst" predictions were distributed.

The second Monte Carlo test attempted to mimic better the types of data records encountered in climatological work. As noted previously, Court's review of Monte Carlo simulations suggested that for annual temperature data, changes in the mean occur over time. Following this concept, the mean of the random numbers within the 3000 separate simulated data records was varied. For each simulated 100-year data record, the mean value of the distribution from which the first 25 random numbers were drawn was arbitrarily set to be 4900, while the mean was 5100, 4950, and 5050 for the second through fourth quarters, respectively. These changes in the mean are an attempt to simulate the fluctuations that might be found in climatological records of HDD totals 100 years in length.

Monte Carlo simulations were also performed in which random numbers drawn from each of the two distributions outlined here were used as input for RMSE and MAE analyses. Again 3000 sets of 100 numbers were drawn from each distribution.

Some caution must be exhibited in reviewing results of optimum length of prediction investigations. A possible dependence of optimum length of prediction results on the time period being investigated has been borne out by Sabin and Shulman (1984). Using the RMSE statistic to study temperature and precipitation data, we observed that the parameter m in equation (1) was of approximately equal importance as n in describing the variation of the RMSE. This may indicate that during different periods, different n-values perform best as predictors, showing that climatic variations occur on different time scales; this can confound attempts to determine the "true" optimum length of prediction. These results could also be interpreted as indicating that data records longer than those presently available will be required before the approximate optimum n-value may be determined with some confidence.

3. Results and discussion

a. Heating degree-day (HDD)–monthly temperature correlations

The results of correlating 12 month seasonal heating degree-day totals with winter temperature sums appear in Table 2. For the stations tested, the common practice of using December, January, and February temperatures to define the relative severity of winters is inferior to longer temperature sums when heating fuel usage (as approximated by HDDs) is the parameter of concern. From these results, two things seem apparent:

1) Past studies which explored the optimum length of record for individual winter months or three-month temperature sums cannot necessarily be assumed to represent adequately the optimum length of record for heating fuel usage data records.

2) For locations at which long HDD data records don't exist, but sufficiently long temperature records do exist, optimum length of record tests run on the sum of monthly temperatures with means below 50°F should yield results most similar to those of actual HDD records.

b. Monte Carlo test results

Results of the two Monte Carlo tests performed to examine characteristics inherent to the methodology of LC appear in Tables 3a–b. The distribution of the 21 000 comparisons of best and worst predictions are exhibited along with the mean percentage occurrence over the 3000 trials. Each error interval (EI) was computed as two times the standard deviation of the corresponding 3000 individual trial percentages. The numbers in the Δ percent column are simply the percent best minus the percent worst for the given n-values. Negative scores indicate that, of the six values tested, running means of that length n are more likely to yield the largest error of prediction than the smallest.

In both Monte Carlo simulations, the five-year running averages were closest to the value being predicted more often than any other n-year average tested, and consistent with the results of LC. Having only computed the best predictor results, LC concluded that five-year running means should be used in predictors of future climatic parameters and heating fuel usage. However, as was hypothesized earlier in this paper, five-year means also were found to be the most likely to have the largest prediction error. In

TABLE 3. Monte Carlo tests of "best versus worst" prediction methodology.

a) For random numbers with mean = 5000 and standard deviation = 375 (number of trials = 3000, each trial's record length = 100).

	Best			Worst			
N	No.	%	EI	No. trials	%	EI	Δ%
5	59,486	28.3	±9.9	82,399	39.2	±11.7	−10.9
10	36,014	17.1	±8.4	37,062	17.6	±8.5	−0.5
15	27,000	12.9	±7.5	24,057	11.5	±7.9	+1.4
20	23,811	11.3	±7.8	19,120	9.1	±7.4	+2.2
25	24,385	11.6	±7.9	18,390	8.8	±6.7	+2.8
30	39,304	18.7	±10.0	28,972	13.8	±12.7	+4.9

b) For random numbers with varying mean (4900, 5100, 4950 and 5050 for first through fourth quarters respectively) and standard deviation = 375 (number of trials = 3000, each record length = 100).

N	No.	%	EI	No. trials	%	EI	Δ%
5	60,296	28.7	±9.9	77,649	37.0	±11.7	−8.3
10	36,586	17.4	±8.6	34,338	16.4	±8.6	+1.0
15	26,362	12.6	±7.4	21,947	10.5	±7.9	+4.9
20	21,838	10.4	±7.7	17,544	8.4	±7.2	+1.3
25	21,443	10.2	±7.5	18,586	8.9	±6.7	+1.3
30	43,475	20.7	±10.0	39,936	19.0	±15.8	+1.7

fact, over the two Monte Carlo tests run, negative Δ percent scores occurred in only 3 of the 12 categories. These negative scores occurred for the five- and ten-year running means in the first Monte Carlo test, and for $n = 5$ in the test in which the mean varied each quarter.

When the mean percentage of best (worst) predictions per trial are considered along with their corresponding error intervals, those n-values whose EIs do not overlap can be said to have significantly different mean percentage occurrence of best (worst) predictions per 100-year simulated data record and $m = 70$ comparisons, at roughly the 95 percent confidence level. For both Monte Carlo tests, none of the mean best percentages for any n-value is significantly better than any other at the 95 percent confidence level. However, for the worst prediction categories there are significant differences. In the constant mean test, the $n = 5$ percentage is significantly higher than those of all other n-values. For the variable mean test, the $n = 5$ mean worst percentage is significantly higher than those for $n = 10$–25, but not $n = 30$.

Keeping in mind the limitations of using only six n-values and discarding much data inherent in this methodology, we can glean some information from the two Monte Carlo tests. Using the Δ percent parameter as a gross measure of skill, one can conclude that five-year running means are not desirable if HDD records exhibit means and standard deviations such as those outlined in these tests. Should HDD records approximate random numbers about a constant mean over time, running means of long lengths would be expected to perform well. However, if HDD records exhibit changes over time of the types specified in the second Monte Carlo test, running means of 15 years in length might be considered to be a better predictor of future HDD totals.

Figure 1 exhibits the results of the two RMSE Monte Carlo tests. The RMSE in simulations with a constant mean continually decreases with increasing n-values. In the tests with varying mean values, the minimal RMSE is found between n-values of 22 and 24 years. The standards deviations of the RMSEs for n-values of 10 through 30 were in the range of 33 to 40 HDDs over the 3000 trials.

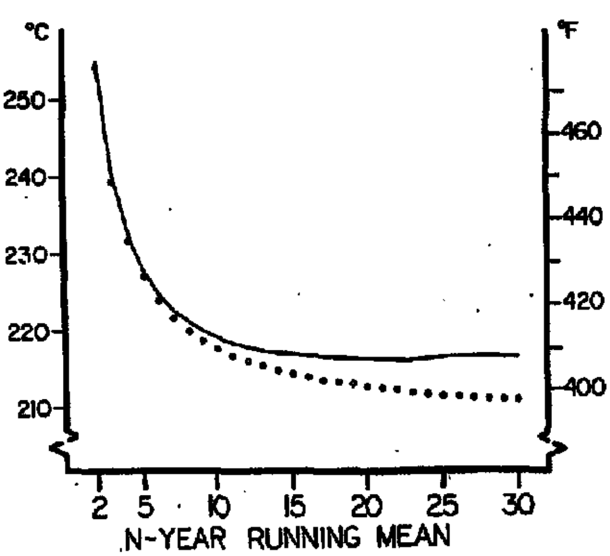

FIG. 1. Monte Carlo results of root-mean-square error of prediction tests as a function of running mean length. Open circles represent results of constant mean test; solid line segments represent results of varying mean test.

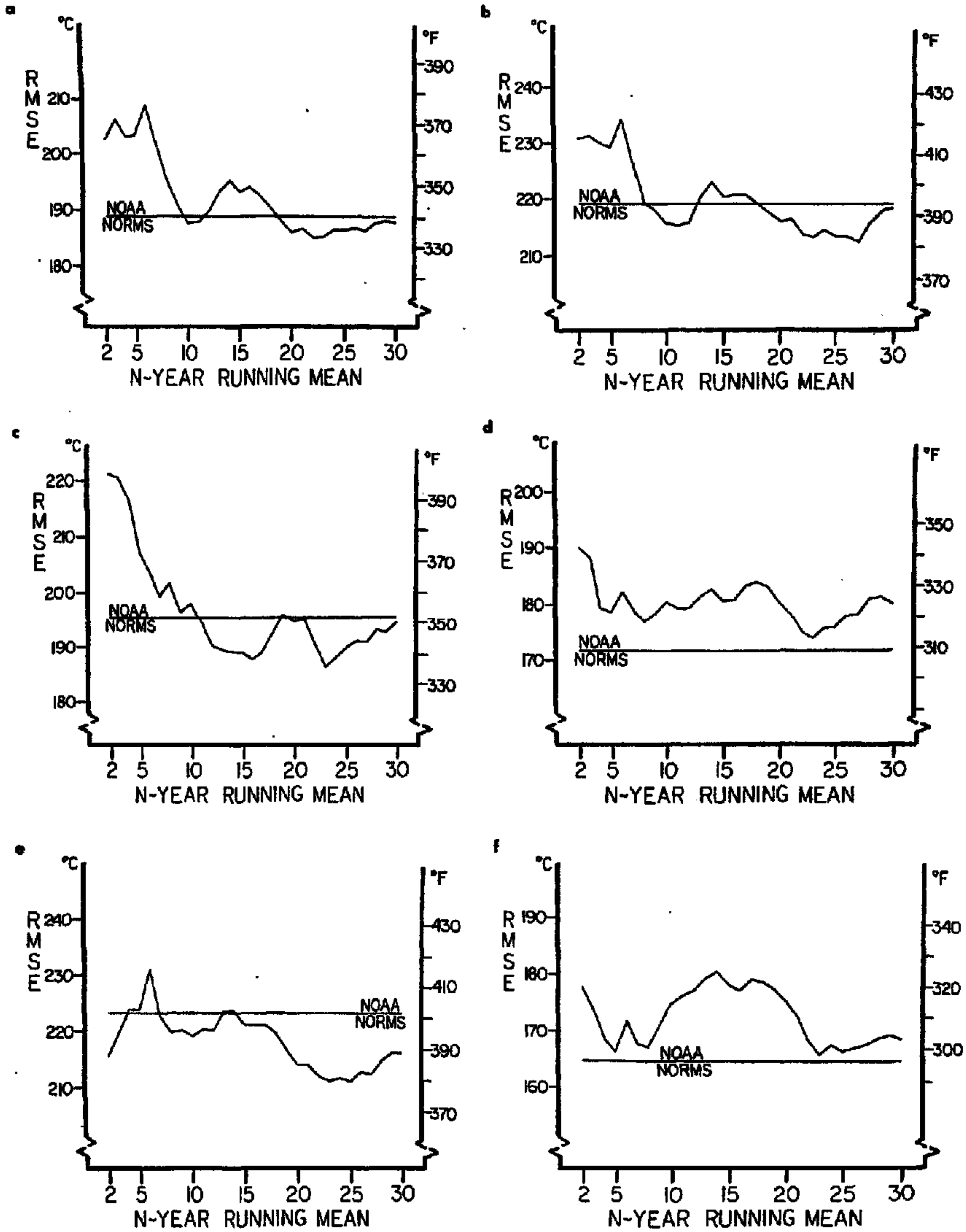

FIG. 2. Root-mean-square error of prediction results for NOAA normals and running mean lengths of 2–30 years: (a) Cairo, IL; (b) Cincinnati Abbe Observatory, OH; (c) Marquette, MI; (d) New York City, Central Park, NY; (e) Parkersburg, WV; (f) Trenton, NJ. (Units are HDD.)

c. Prediction ability tests using station data

Figures 2a–f show that, as in many past studies, few clear-cut conclusions can be made that are valid for all locations tested.

In Table 4, it is shown that for the *n*-values of 2–30 inclusive, the smallest RMSE (best prediction) length was found to be in the 20s at all locations (as in the Monte Carlo test with varying means). The largest RMSE values were for *n*-values of between 2 and 14. These results are consistent with previous studies.

The patterns of the plots of RMSE versus *n*-value for Cairo and Cincinnati Abbe Observatory are quite similar, and to a lesser extent so is the data for Parkersburg. Such results agree with Court's observations that stations in the same region tend to yield similar results in RMSE analyses.

The RMSE performance of the NOAA normals varies widely over the six stations tested. In general, NOAA normals performed better in the east (NYC and Trenton) than in the Ohio Valley. Part of this difference could possibly be traced to the procedure used by NOAA to formulate NOAA HDD normals. The normals are not merely 30-year averages. Instead, empirically derived relations are employed which use monthly temperature statistics for all months to yield typical monthly HDD values. It could be that the method chosen for use at all stations in the United States is more valid in the New Jersey, New York area, than in the Ohio Valley.

It is particularly notable that the NOAA normals outperformed all *n*-values tested at Trenton and NYC, according to the RMSE statistic.

The lowest MAE values were observed to occur for lower *n*-values than was the case for the RMSE statistic at five locations (Figs. 3a–f). Specifically, the lowest MAE scores were for *n*-values of 4 (Cincinnati, New York City), 5 (Parkersburg, Trenton), 11 (Cairo), 23 (Marquette). Combining the results of MAE and RMSE analyses leads to the observation that, while running mean lengths shorter than 15 years usually yielded the lowest average error, *n*-values greater than 20 consistently minimized the squares of the errors.

Inspection of the results of the best versus worst methodology reveals that at five of the six locations, predictions using $n = 5$ years of data produced the smallest error more often than the other *n*-values tested (Figs. 4a–f). This was expected from LC's analyses, and from the Monte Carlo simulations displayed previously. At all six locations the $n = 5$ predictions were also most often the farthest away from the predictand, as was hypothesized and simulated in the Monte Carlo tests.

The results for NOAA normals in the best versus worst methodology shown in Figs. 4a–f were calculated after the results for the six *n*-values were tabulated. So, if a NOAA normal gave a lower error than the best *n*-value error, it was noted. Likewise, for the worse error designation, when the NOAA normal produced an error greater than the others, it was tabulated. This did not change the results for the six *n*-values, which still sum to 30 for each station and error type.

Over all locations, the NOAA normals performed fairly well using the best versus worst comparisons. In 34 of the 180 cases, the NOAA normal was better than all *n*-year running mean predictions, while 26 times it had the largest error.

4. Conclusions

Valid conclusions concerning the optimum length of prediction can best be made by the analysis of real data, and by using Monte Carlo simulations in addressing this problem. Results obtained using real data from a limited number of locations can be misleading due to random variability in such results. This variability is evident in the relatively large standard deviations found in Monte Carlo tests of these statistical procedures. However, Monte Carlo experiments alone cannot be relied on to answer questions concerning the optimum length of prediction, since real data do not exactly fit theoretical distributions.

In this inquiry data from six stations and a Monte Carlo simulation using varying means both indicated that RMSEs are minimized for *n*-values in the low 20s. The variability of RMSEs for given *n*-values show that there is little difference in the predictive abilities of *n*-values of 10–30 years.

Lamb and Changnon's "best predictor" method has been shown to produce results easier to interpret than RMSE analyses, but the method is limited in that much of the information contained in the data records can be ignored.

Possible regional differences in the NOAA HDD normal predictive abilities were indicated from results at the six sites examined. Further studies using data

TABLE 4. Running mean length *n* with the lowest and highest root-mean-square error values at six stations.

	Cairo	Cincinnati	Marquette	New York City	Parkersburg	Trenton
n-Value of lowest rmse	23	27	23	23	23	23
n-Value of highest rmse	6	6	2	2	6	14

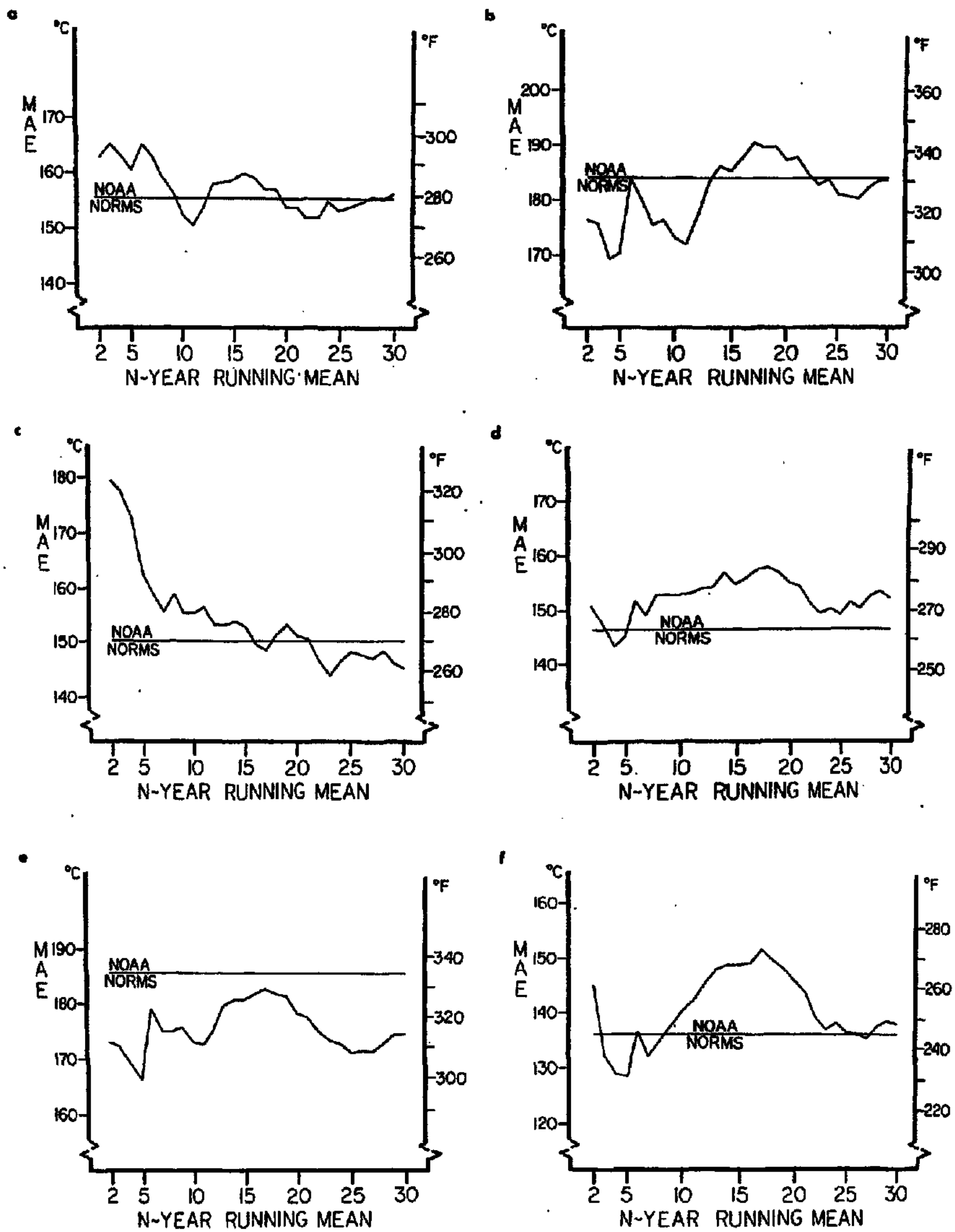

FIG. 3. Mean absolute error of prediction results for NOAA normals and running mean lengths of 2–30 years; station letters as in Fig. 2.

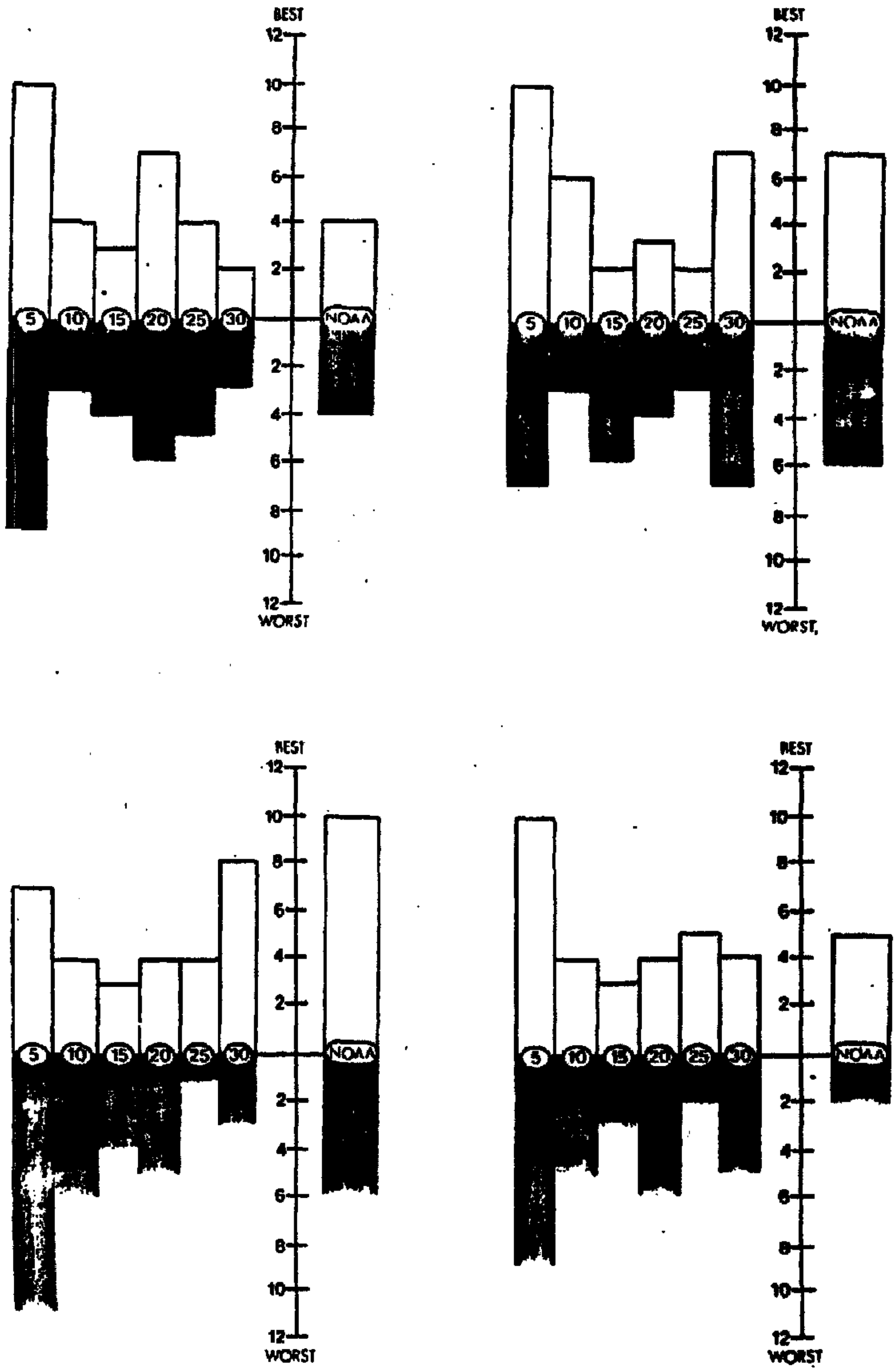

FIG. 4. Best versus worst predictor methodology results for NOAA normals and for running means of 5, 10, 15, 20, 25, and 30 years in length (station letters as in Fig. 2).

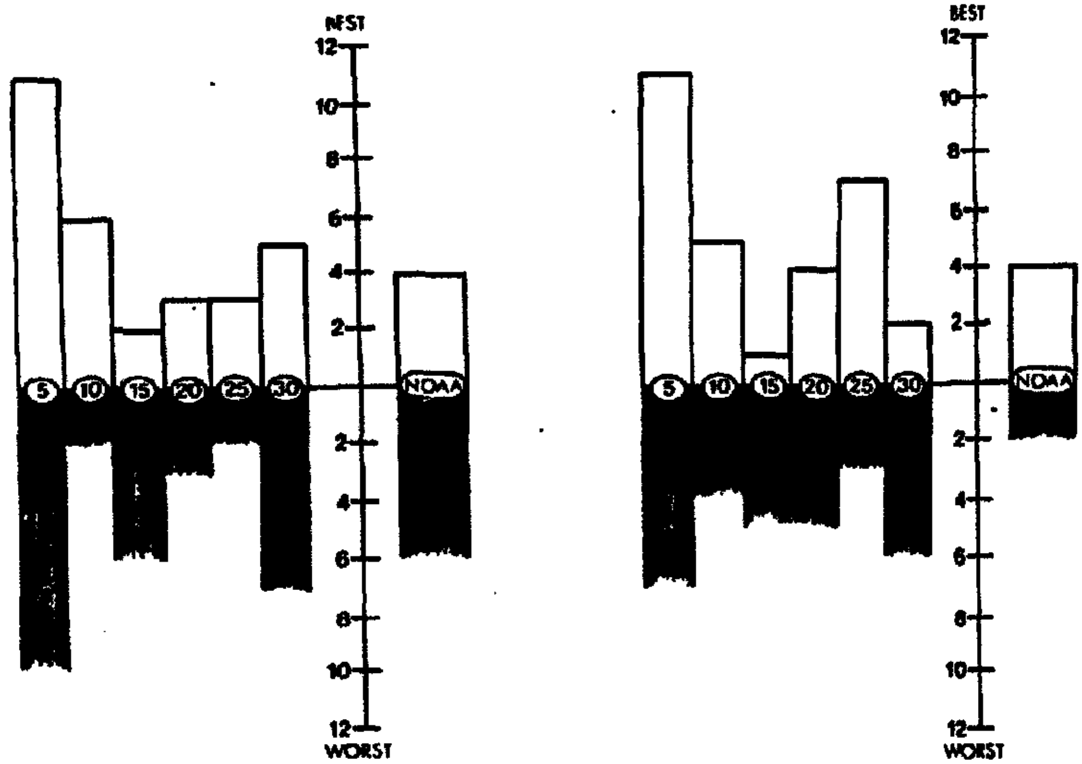

FIG. 4. (*Continued*)

from a greater number of locations could show if this regional difference does truly exist.

Clearly, careful thought must be given to selecting which criterion should be used to determine the normal length with predictive abilities most appropriate for the problem at hand. Combining the results of this inquiry and previous investigations leads to the following observations.

- If one seeks to minimize the average prediction error over a number of years, the MAE statistic is the most appropriate test and 10- to 30-year normals generally have performed best in tests using both real data and random number series. Tests utilizing climatic data records suggest that averages as short as five years in length perform as well as longer averages at some locations, based on the MAE statistic.
- If a more conservative approach is called for, in which over the long term it is desirable to minimize the occurrence of large prediction errors, the RMSE statistic is the criterion of choice. Most inquiries using this test, point to running mean lengths of 15–30 years in length as being the optimum normal length. Monte Carlo tests especially suggest that normals less than ten years in length should be viewed with some skepticism if minimizing the square of the errors is desirable.
- Lamb and Changnon's "best predictor" approach is appropriate in cases when the magnitude of the prediction error is not of great concern. This method, used in its simplest form, is most suitable for problems in which it is the aim to "win" with the best prediction most often, and of little or no interest of how bad the "losses" are.
- The fact that HDD data do not represent a continuous, stationary time series with a constant mean, variance, skewness, and so on, is the underlying reason for the ambiguity in the results of all such inquiries using real data. In practice, climatic variation on all time scales and inhomogeneities due to observer, instrument, and microclimatological changes lead to nonhomogeneous data records. It is quite possible that the limiting factors that reduce the optimum length of prediction below 20 years at some locations are the changes in instrumentation and in the environment surrounding the station, and not large or regional scale climatic changes.

Not until seasonal temperature forecasts with sufficient lead times show increased levels of skill and reliability than at present, will normals be less relied on as predictors of future environmental conditions. The results presented herein using HDD data agree with results of various past studies that point to the use of normals based on 10 to 30 years of data as being the most efficient way of defining the climate for predictive purposes.

Acknowledgments. This work was performed as a part of the New Jersey Agricultural Experiment Station (NJAES) Project D13101-3-83, supported in part by the New Jersey Agricultural Station and Hatch Act funds. Thanks are extended to Mr. J. R. Lanzante for his comments concerning Monte Carlo testing, and Ms. M. R. DeSantis for her help in editing the manuscript.

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