



Forecasting for Regulators: Current Issues and Trends in the Use of Forecasts, Statistical, and Empirical Analyses in Energy Regulation

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Introduction -- Topics

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Introduction

What is a forecast?

Definition: Projection or development of conclusions regarding likely outcomes that have not yet occurred.

Common elements:

- (1) Uncertainty about the future.
- (2) Typically uses some combination of empiricism and judgment.
- (3) Expected future usually based on observed past.

How are forecasts used in the regulatory process?

The terminology between “forecasts” and standard empirical analysis often gets cluttered since both use historic data to make inferences about likely outcomes either yesterday (“backcast”), today, or in the future.

Common uses of forecasts in the regulatory process can be generalized into:

- (1) Ratemaking purposes: forecasts can be used to establish test year information.
- (2) Resource planning purposes: supply and demand-side resources needs over time. Most IRP principles recognize that the first step is development of a reliable forecast.
- (3) Other special purposes: truing up data, benchmarking and performance goals, normalization (i.e., weather, other factors).

Rates, Test Years, and Regulation

The “regulatory compact,” as a general term, gives utilities the opportunity to earn a fair rate of return on their investments and prudently-incurred costs. In return, they are expected to provide safe, reliable, and economic service.

The first part of the compact defines the concept of the rate case, while the second part defines what utilities are expected to do between rate cases for those returns.

Determining “costs” and “value” have been considerable academic and applied challenge since the early days of regulation.

Unfortunately, the real world falls short of the ideals of economic theory since legal standards define this as a reasonable process.

Test Years and Test Periods

The “test year” is a basic concept used throughout utility regulation to define the time frame within which rates are set. Some differentiate the “test period” as a more refined version of this concept that takes the “known and measurable” adjustments into account. Can often be used with terms such as “rate period” and “rate year.”

Selection of the test year and its corresponding test period adjustments can be controversial.

Criticisms is that these conditions have passed and are not likely to be reflective of future operating conditions. The more dated the test year, the more challenged and controversial, the ratemaking process.

Rejoinder is that there is legal and policy obligation to base test years on known and measureable information.

Historic versus Projected Test Years

The potential “staleness” of historic test years has led some states to adopt forecasted test years which is a projection of the anticipated outlook in some upcoming year.

A forecasted test year can suffer from a problem similar to a historic test year since the forecast can become more speculative the further removed it is from the current period.

Can lead to a process that includes considerable debate, judgment, and in some instances compromises.

Current, there are an estimated 31 states that use strict historic test years, 4 states that use strict forecasted test years, and 15 states that allow utilities to choose between forecasted or historic.

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Forecasting methods

Forecasting Methods -- Common Types

Variety of different forecasting types can arise in the regulatory process. These can be generalized into the following types each with their own strengths and weaknesses.

Structural/stochastic approaches (econometrics)

Astructural/stochastic approaches (time series)

Structural/deterministic

Combination of Forecasts

Forecasted Inputs/Third Party Forecasts

Forecasting Methods -- Common Types**Structural/stochastic approaches (econometrics)**

“Stochastic” since these approaches are based on statistical estimation principles.

Common econometric models, typically focused on demand modeling, that can take a variety of functional forms.

Most common approach is a log-linear model that posit that energy demand (kWh, KW, Dth) is a function of prices, income, weather, and other factors.

Long historic that dates to the early 1970s on this more aggregate approach.

Most common approach used by utilities in regulatory filings of all types.

Input data comes from internal historic information.

Forecasted input data (like income) typically comes from third-party sources.

Forecasting Methods -- Common Types**Astructural/stochastic approaches (time series)**

These approaches tend to be agnostic about the functional form and relationships/factors influencing demand.

Since these factors are based upon approximations of theory, and data can be unreliable and not representative of the true relationships (i.e., price), only a time series can produce least-biased output.

Autoregressive (“AR”), moving average (“MA”), integrated (“I”), approaches are used and combined (AR, MA, ARMA, ARIMA).

Variations not uncommon on relatively smooth moving trends like customer forecasts. However, can be used to model energy use and energy use per customer as well.

Forecasting Methods -- Common Types**Structural/deterministic**

“Deterministic” entails that models have no randomly distributed-properties. In other words, they are not statistically estimated but based upon a pre-defined (axiomatic) set of relationships. Can be very “black-box” in nature.

Basic ***class cost of service model*** can be thought of as a “deterministic” model of costs since it is based upon a set of assumed relationships (i.e., functional relationships and cost allocation factors).

Multi-areas dispatch models: based on a linear or non-linear optimization model.

Valuation modeling: income, market, and cost approach used in some states for rate base.

Cost-effectiveness modeling: mathematical relationships on “costs” and “benefits” that rise to differing stakeholders: utility, participant, non-participant, all ratepayers, society.

Forecasting Methods -- Common Types**Combination of Forecasts**

Based upon the conclusion that any two unbiased forecasts can be combined to produce an equally unbiased forecast with increased performance.

Useful method when you have two models with offsetting performance issues. The “derivatives” approach to forecasting.

Key: “any two unbiased forecast.”

Key: how forecasts are combined or weighted. Does require some subjectivity.

Despite usefulness, not commonly used.

Cannot be used in all situations, depends on the models and their purpose. Combining can, in some instances, take two unbiased forecasts/estimates to create a biased forecast/estimate. (i.e., valuation modeling)

Forecasting Methods -- Common Types**Forecasted Inputs/Third Party Forecasts**

Generalized term for using forecasts and inputs from a third party. These parties develop and maintain their own proprietary modeling data and methodologies and sell the results to utilities or regulatory commissions.

Utilities often subscribe to these forecasts particularly economic outlooks.

The origins for many of these companies are common, but players and names have changed with mergers and acquisitions in this business.

Global Insight commonly used source for forecasted information.

Many states will use their own independent forecasting sources for certain types of information (Indiana Utility Forecasting Group, Florida Legislative Research).

Forecasting Method – Relative Advantages

Models	Data Requirements	Technical Requirements	Parsimony	Robustness	Gamemanship
Structural/Stochastic	Moderate	High	Moderate-Low	Moderate-Low	Moderate-High
Astructural/Stochastic	Low	Moderate	High	Moderate	Moderate-Low
Structural/Deterministic	High	Moderate-High	Low	Moderate-Low	High
Combination	Low-Moderate	Low	High	Moderate-Low	High
Third-Party Forecasts	Low	Low	High	NA	High

What Makes a Good Forecast?

- (1) Data, inputs and assumptions
- (2) Parsimony and consistency
- (3) Robustness
- (4) Predictability and replication

Data, inputs and assumptions

Any empirical model is a function of its data, input and assumption. The common adage of “garbage in, garbage out” is very true in forecasting and empirical modeling generally.

Common data problems:

- Unique and not publicly available series.

- Calculation errors.

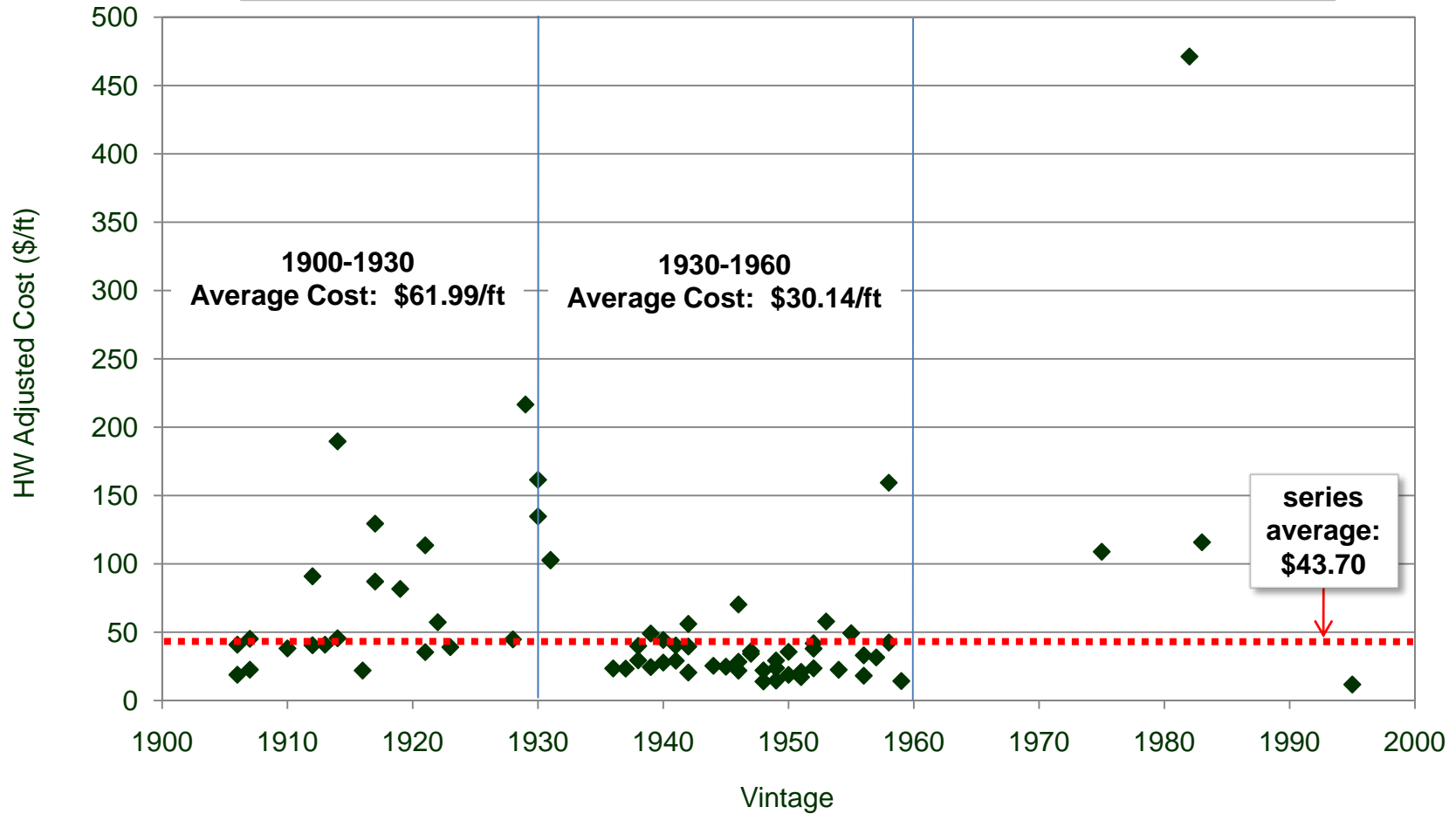
- Transformation/standardization errors.

- Missing values

- Outliers

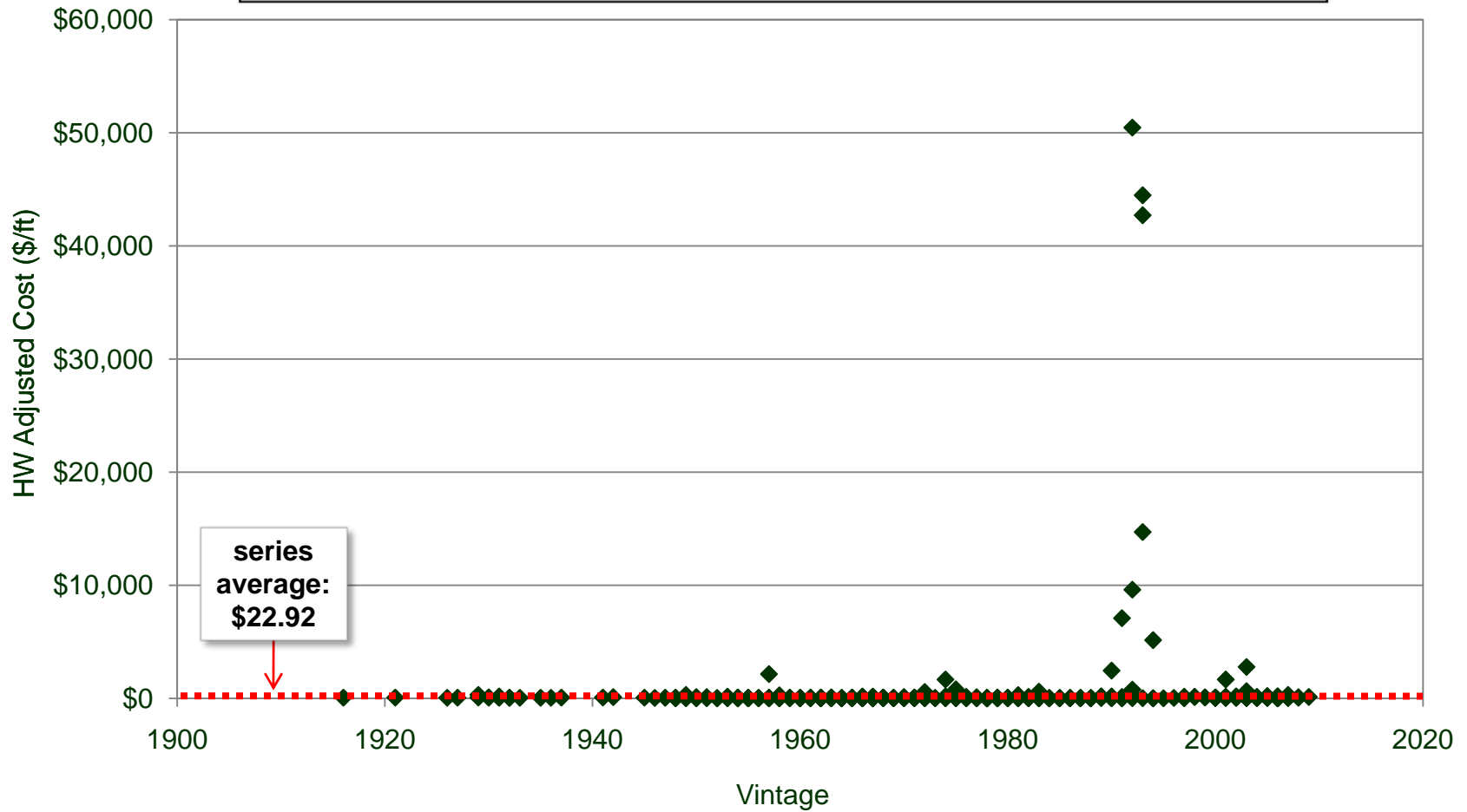
Forecasting – Best Practices – Data and Assumptions

Cast Irons Mains Embedded Costs for Zero-Intercept Model



Forecasting – Best Practices – Data and Assumptions

Unprotected Steel Embedded Costs for Zero-Intercept Model



Parsimony and consistency

Parsimony: the simplest and most frugal route of statistical explanation available. Commonly-facilitated goal for science, math, and statistics.

Does not mean “dumbing-down” the analysis.

Does mean that analytic complication for the sake of analytic complication is a waste of computational effort, regulatory resources, and at worst, a potential sign of empirical gamesmanship.

Consistency: analyses that follow academic literature, utility, and/or regulatory practice.

Utility is a rich area that has a long history of combining the best of theory and practice. New analytic innovations that offer better insights or enhanced predictability should be welcomed, but weighed against the dollars/issues at stake.

Forecasting – Best Practices**Robustness:**

Model, forecast or empirical approach can be said to be robust if changes in one or two inputs or assumptions do not lead to wild swings in the results.

Does not mean that predicted output cannot be variable or even volatile (i.e., wholesale power prices, energy commodity prices).

Robustness can be subjective in evaluating “large” changes in order of magnitude.

Robustness can be less subjective in evaluating changes in direction or sign (i.e., results that move from positive to negative and vice versa).

Many times, robustness can be an goal of ideal, and is simply a function of the analysis. (i.e., weather impacts on demand, free ridership on energy efficiency cost-effectiveness)

Predictability and Replication

There are a variety of measures that examine overall empirical “goodness-of-fit.” Commonly used summary statistic is referred to as “R-squared” which is also called the “coefficient of determination,” or the square of the “correlation coefficient.”

R-square, however, is not the only measure, and can actually be an inappropriate measure in comparing models of different composition since often adding regressors can inflate R^2 values. Also – “correlation is not causation.”

Make sure variable signs are significant and of the correct signs

Replication: from a regulatory perspective, it is imperative that forecasts and models be replicated. It is simply bad regulatory practice to accept forecasts at face value without additional checks.

Avoid taking results from deterministic models that cannot be replicated. Black box results also create bad precedent.

Common forecasting adjustments (usage)

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Common forecasting adjustments (usage)

Common Forecasting Adjustments: Demand/Billing Determinants

Demand or billing unit data is often changed or modified in the ratemaking and/or planning process in order to account for a variety of anticipated changes that may be the result of policy or other factors.

Common adjustments include:

- *Weather normalization*
- *Income/economic adjustments*
- *“Unusual” events (ice-storms, hurricanes, catastrophes)*
- *Price change, stimulation or repression*
- *Energy efficiency*

Common Forecasting Adjustments: Demand/Billing Determinants – Weather

Weather normalization adjustment is not the same as a weather normalization clause tracker.

Weather normalization, in context of “forecasting,” is process to standardize billing units for “normal” weather.

Weather normalization clause is an ongoing tracker to adjustment monthly bills for “normal” weather-related/influenced use.

Normalization moves billing determinants to the “average” or “typical” use level. So if period in question has colder than normal weather, and greater than average HDDs, billing determinants will be adjusted downwards, and vice versa.

Why is “normal” weather an issue?

Global warming/climate change has served as source of fuel for this debate.

Until recently (roughly last 2 years), a warmer-than-average winter weather cycle that was particularly evident in the mid-west and western U.S.

Many utilities believed that the standard definition of “normal” was not picking up this trend appropriately and that the period for defining “normal” weather should be re-defined.

Many utilities took the position that defining shorter periods for normal weather were better predictors of the current trends.

Common Forecasting Adjustments: Demand/Billing Determinants – Weather

Weather normalization adjustments can range from the very simple to the very complicated.

The empirical/analytic challenge is developing a set of weather-related parameters that define (in unbiased fashion) the relationship between weather and energy use.

As a general rule, the results from a load forecast can be used to establish these parameters, although often that is not the case.

Most often, the debate does not focus on the estimation of weather parameters as it does in defining the “normal” period for establishing “normal” weather.

This becomes a policy debate as much as it does an empirical debate

Common Forecasting Adjustments: Demand/Billing Determinants – Weather

Policy questions on defining “normal” weather:

Distinction needs to be made between “cycle” and “trend.”

(a) What adjustment are we really making? Is this a forecast or a normalization process?

(b) Regardless, should the ratemaking process be based on cycles or trends?

(c) What is the best time period to set for normal weather if a change is determined to be appropriate? (5 years, 10 years, etc.)

(d) Should any changes in revenue recovery risk be identified in the ratemaking process?

Common Forecasting Adjustments: Demand/Billing Determinants – Weather

Company	Number of Months Covered by Clause	Mechanism Type	Customer Classes	Number of Years (Normal)
Alabama				
Alagasco	12	1	Residential, Small Commercial and Small Industrial	n.a.
Arkansas				
Arkansas Western Gas	6	1	Residential, Commercial	30
CenterPoint Energy	6	2	Residential, Small Commercial	30
Arkansas Oklahoma Gas	6	1	Residential, Small Business	30
Georgia				
Atmos Energy	12	1	Residential, Commercial	n.a.
Indiana				
Indiana Gas	7	1	Residential, General	30
Southern Indiana Gas & Electric	7	1	Residential, General	30
Citizens Gas & Coke Utility / Westfield Gas	7	1	Residential, Small General	30
Nine small gas distribution companies	7	1	Residential, General	30
Kansas				
Atmos Energy	12	1	All	30
Aquila	12	2	All	30
Kansas Gas Service Company	12	2	Residential, General	30
Kentucky				
Atmos Energy	7	1	Residential, Commercial, Public	30
Columbia Gas	5	1	Residential, Small General	30
Delta Natural Gas	5	1	Residential, Small General	30
Louisville Gas and Electric	6	1	Residential, Commercial	30
Louisiana				
Atmos – Louisiana Gas Service	4	1	Residential, Commercial	n.a.
Atmos – Trans Louisiana Gas	4	1	Residential, Commercial	n.a.
Maryland				
Columbia Gas	5	1	All	30

Common Forecasting Adjustments: Demand/Billing Determinants – Weather

Company	Number of Months Covered by Clause	Mechanism Type	Customer Classes	Number of Years (Normal)
Mississippi				
Atmos Energy	6	1	Residential, General	30
Centerpoint	n.a.	n.a.	n.a.	n.a.
North Dakota				
Montana-Dakota Utilities	7	1	Residential, General	30
New Jersey				
Elizabethtown Gas	8	2	Residential, General	20
New Jersey Natural Gas	8	2	Residential, General, Economic Dev.	20
South Jersey	8	2	Residential, General	20
New York				
Consolidated Edison	7	1	All	30
KeySpan Energy Delivery	7	1	Residential, Firm Transport	30
National Fuel Gas Distribution	7	1	Residential, General, Small Cogeneration	30
New York State Electric & Gas	8	1	All	30
Niagara Mohawk	8	1	Residential, Small and Large General, Transportation	30
Orange & Rockland Utilities	8	1	Residential, General, Firm Transportation	30
Rochester Gas & Electric	8	1	Residential, General, Firm Transportation	30
Oklahoma				
Arkansas Oklahoma Gas	6	2	Residential, Small Business	10
Oklahoma Natural Gas	8	1	Residential, Commercial, Industrial	30
Oregon				
NW Natural	6	2	Residential, Commercial	25
Pennsylvania				
Philadelphia Gas Works	8	2	General, Municipal, Public Housing	30
Rhode Island				
Narragansett Electric	6	1	All	n.a.
South Carolina				
Piedmont Natural Gas	5	2	Residential, Commercial	30
South Carolina Electric & Gas	6	1	Residential, Small and Medium General	n.a.

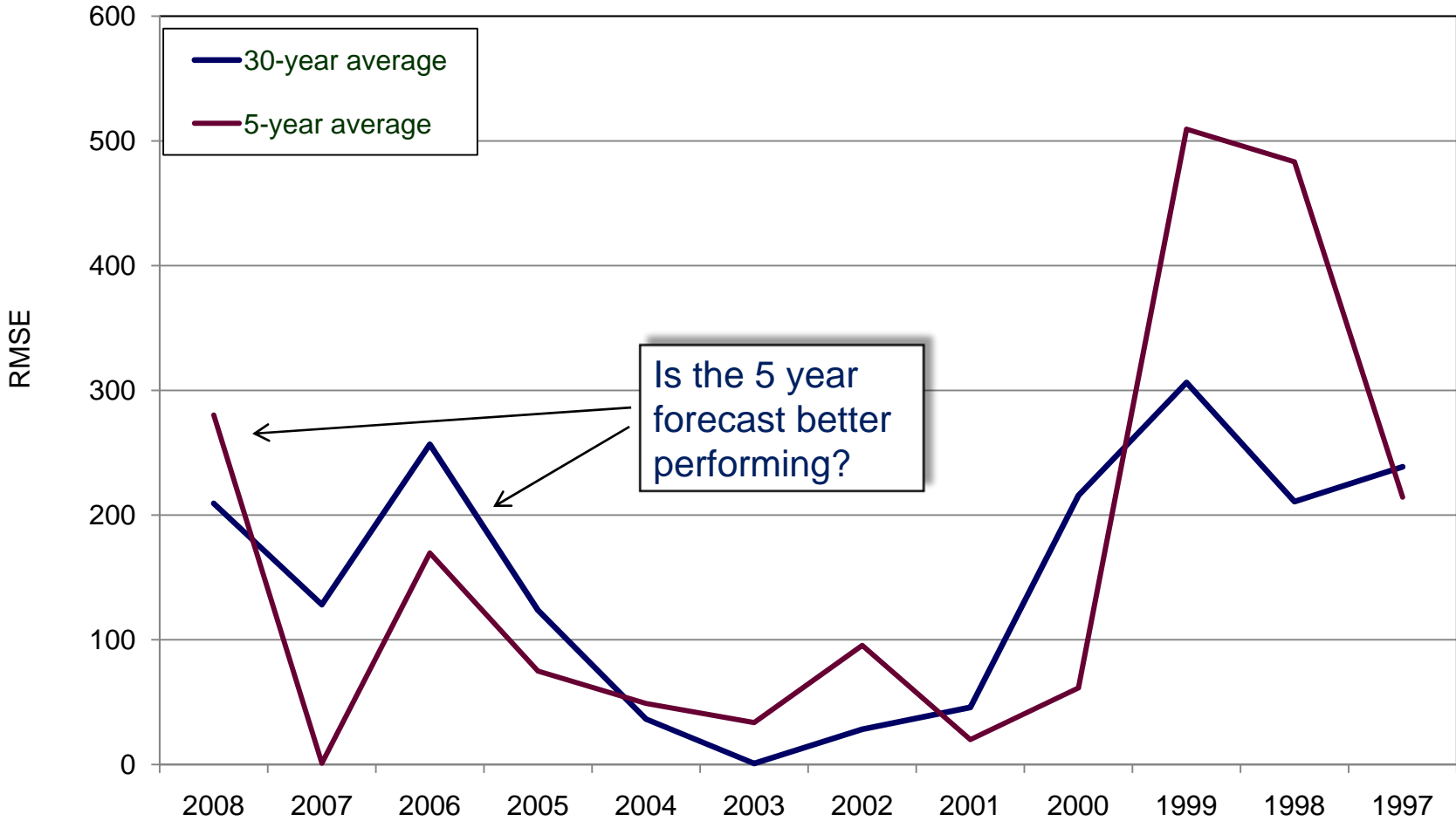
Common Forecasting Adjustments: Demand/Billing Determinants – Weather

Company	Number of Months Covered by Clause	Mechanism Type	Customer Classes	Number of Years (Normal)
South Dakota				
Montana-Dakota Utilities	7	1	Residential, General	30
Tennessee				
Atmos Energy	6	1	Residential, Commercial	30
Chattanooga Gas	6	1	Residential, Commercial	30
Piedmont Natural Gas	5	1	Residential, Commercial	30
Texas				
Atmos Energy	8	1	Residential, Commercial, Public	
Utah				
Questar Gas	12	1	Residential, General	30
Virginia				
Appalachian Natural Gas Distribution	12	1	All	30
Atmos	12	1	Residential, Small Commercial	30
Roanoke Gas	12	1	All	30
Southwest Virginia Gas	12	1	All	30
Virginia Natural Gas	6	1	Residential	30
Washington Gas Light	8	1	All	135*
West Virginia				
Eight small LDCs	12	1	Residential, Small Commercial	30
Wyoming				
Questar Gas	12	1	General	10

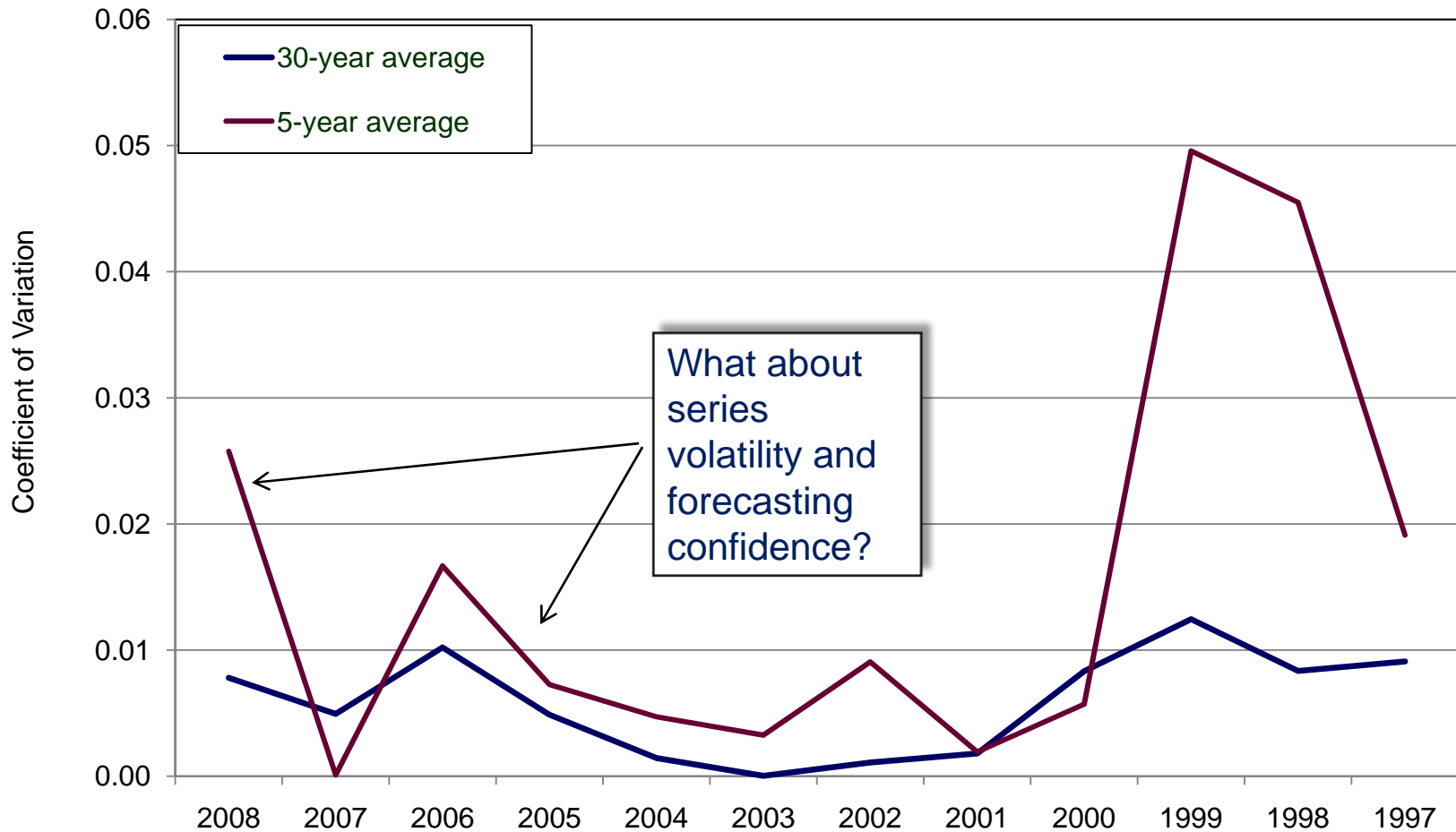
Note: n.a. is not available.

*Washington Gas Light's definition of normal weather is based on a trendline regression analysis. The Virginia Division uses 135 years; the Shenandoah Division uses 25 years.

Common Forecasting Adjustments: Demand/Billing Determinants – Weather



Common Forecasting Adjustments: Demand/Billing Determinants – Weather



Common Forecasting Adjustments: Demand/Billing Determinants – Weather

Year	Percent ROE with WNA	Percent ROE without WNA	Difference
1994	11.97%	12.05%	0.08%
1995	11.34%	9.79%	-1.55%
1996	12.38%	13.52%	1.14%
1997	12.35%	11.71%	-0.64%
1998	11.53%	8.19%	-3.34%
1999	12.46%	10.48%	-1.98%
2000	12.74%	12.28%	-0.46%
2001	15.05%	13.80%	-1.25%
2002	8.49%	6.40%	-2.09%
2003	10.44%	11.57%	1.13%
2004	10.84%	10.45%	-0.39%
2005	7.42%	7.05%	-0.37%
2006	7.04%	5.13%	-1.91%
2007	11.93%	10.98%	-0.95%
2008	11.27%	9.84%	-1.43%
Average	11.15%	10.22%	-0.93%

Connecticut DPUC found that SCG's WNA had not equally benefited ratepayers and the Company.

During the time SCG's WNA was in place, SCG received a total of \$43.6 million in net WNA revenue.

Ratepayers benefited in only three of the 15-plus years. Further, the Company's ROE benefited significantly.

The average ROE with the WNA was 11.15% versus 10.22% without a WNA, an increase of 93 basis points.

Income/Economic Adjustments

Utility forecasts will tend to include an economic projection developed by third-party commercial sources (or independent state forecasting units) to extrapolate loads and/or customer growth.

Can become problematic in a recession since the economic activity during these periods is not “normal.”

If recession year billing determinants are used, utility will have considerable up-side opportunities post-rate case.

“Unusual Event” Adjustment

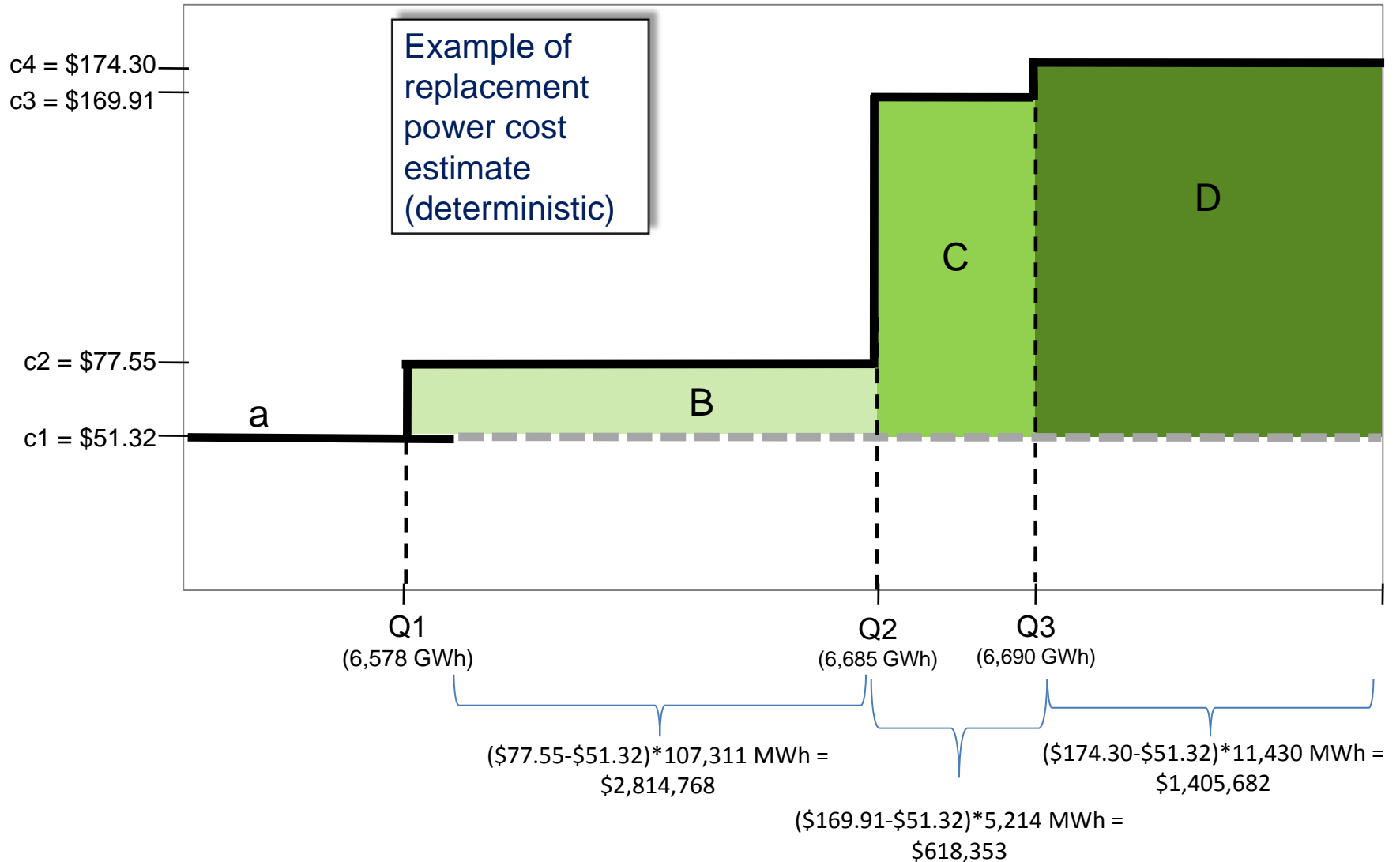
A related type of economic/load adjustment that can be made by utilities during rate cases or other types of regulatory proceedings

These are often related to the economic adjustments discussed earlier since:

- (a) they can tend to be based off (or used with) the same models.
- (b) they reflect a one-time event that is not normal to standard operations

Examples can include weather-related events, usually resulting in large scale outages. Can include other factors such as large-scale transmission-generation outages.

Common Forecasting Adjustments: Demand/Billing Determinants – Unusual Events



Common Forecasting Adjustments: Demand/Billing Determinants – Price**Price Elasticity Adjustment**

Price elasticity defines the percentage change in quantity demanded resulting from a percentage change in price.

Like other parameters, it can usually be extracted from unbiased load forecast or other statistical demand analysis.

Can be used to adjust billing determinants for significant changes in price.

Use in typical ratemaking for electric and gas has been “hit-or-miss.”

Considerable discussion in the early 1990s as means of adjusting for the risk-shifting nature of revenue decoupling (but not adopted).

Energy Efficiency Adjustment

The role of energy efficiency on usage will be ongoing modeling challenge.

For gas distribution industry, no good source of information to use to do broad analysis.

Modeling typically limited to time trend variables (not very explanatory).

Electric slightly better.

Empirically, could be a situation that creates endogeneity problem – no real general equilibrium/simultaneous equation methodology for doing integrating these impacts over time.

Common empirical adjustments (costs)

4

Common empirical adjustments (costs)

Performance-based regulation (PBR) mechanisms

Forecasting and empirical analysis process clearly drives home the common observation of the asymmetrical level of information that exists between regulators and regulated utilities.

One means of avoiding these forecasting problems is the use of PBRs.

PBRs are form of formula-based rates that allow prices to increase based upon a prescribed formula.

The formula takes into consideration general inflation with offsets for productivity and other adjustments. Typically accompanied by earnings sharing.

Common Empirical Adjustments (Costs) – PBR Mechanisms

$$I = \frac{GDPPI_y}{GDPPI_{y-1}} - X - 1$$

$$X \text{ Factor} = [(trend \ Input \ Prices_t - trend \ Input \ Prices_g) - (trend \ PFP_t - trend \ PFP_g) - C - A]$$

PBR may not be a complete panacea for avoiding forecasting/empirical issues since the initial mechanism should be established using empirical analyses.

Consumer dividends and accumulated inefficiencies factors can also be represented by empirical measures.

Common Empirical Adjustments (Costs) – Inflation Adjustments**Partial approaches: net inflation factors**

Several recent proposals in many jurisdictions is to simply apply a limited inflation factor.

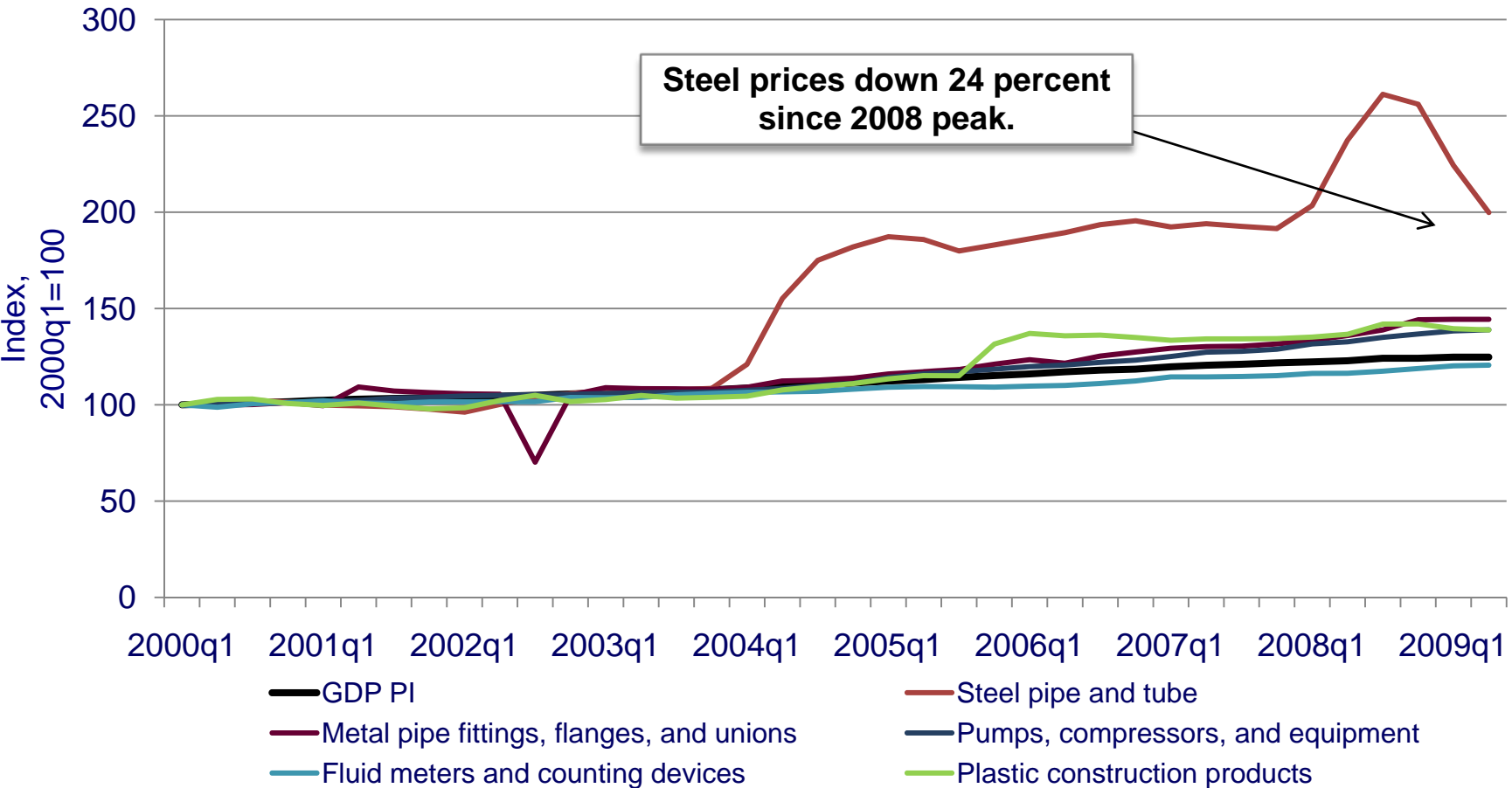
In some instances, these proposed factors would simply allow utility to increase prices based upon GDP-PI or CPI.

In other instances, they are modified forms of PBR that have a productivity offset and are applies to some subset of costs (like O&M).

Important to understand historic changes inflation, as well as the regulatory policy problems created by limited mechanisms of this nature.

Common Empirical Adjustments (Costs) – Inflation Measures

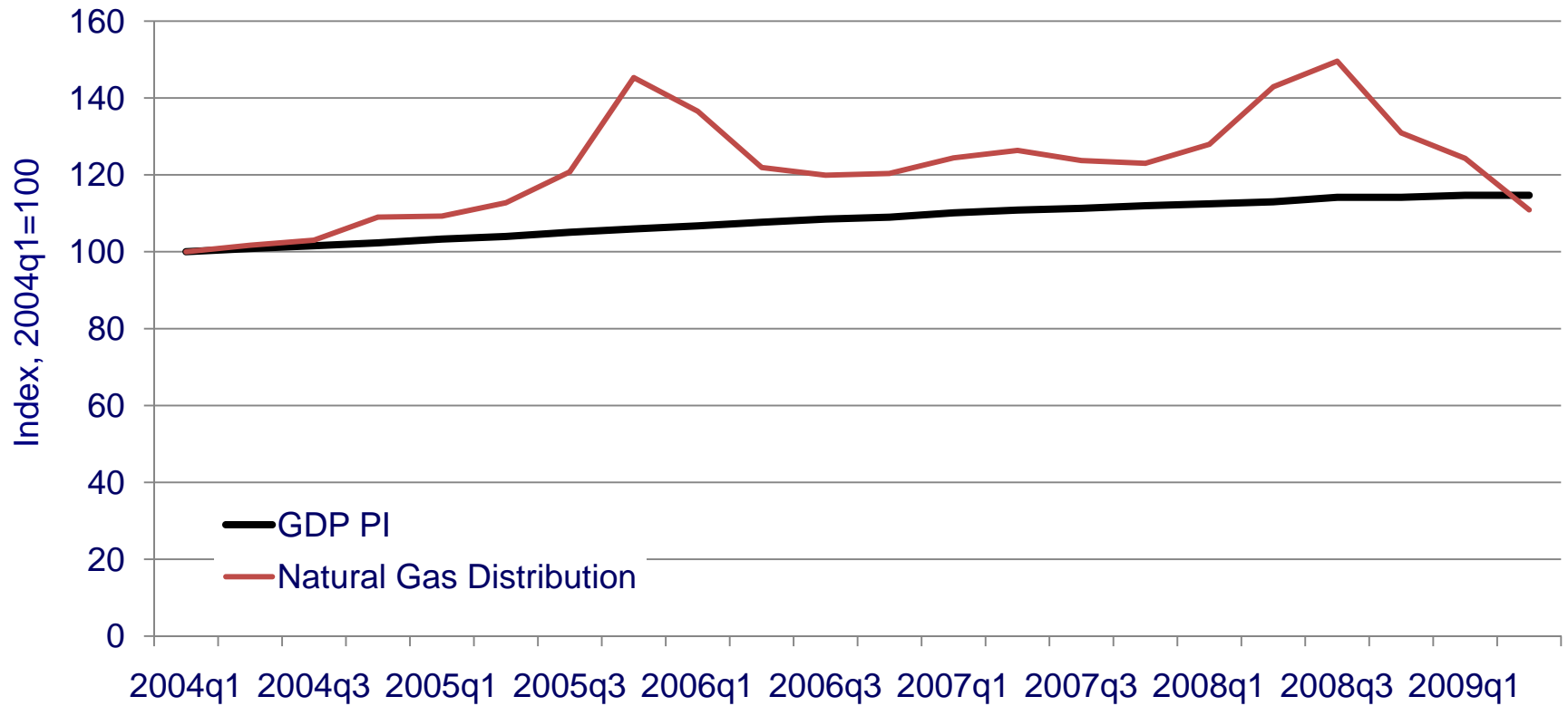
For the natural gas industry, commodity and capital cost input increases are recent anomalies relative to historic trends. The longer run trend is comparable to the overall level of inflation.



Source: Bureau of Labor Statistics, U.S. Department of Labor; and Bureau of Economic Analysis, U.S. Department of Commerce.

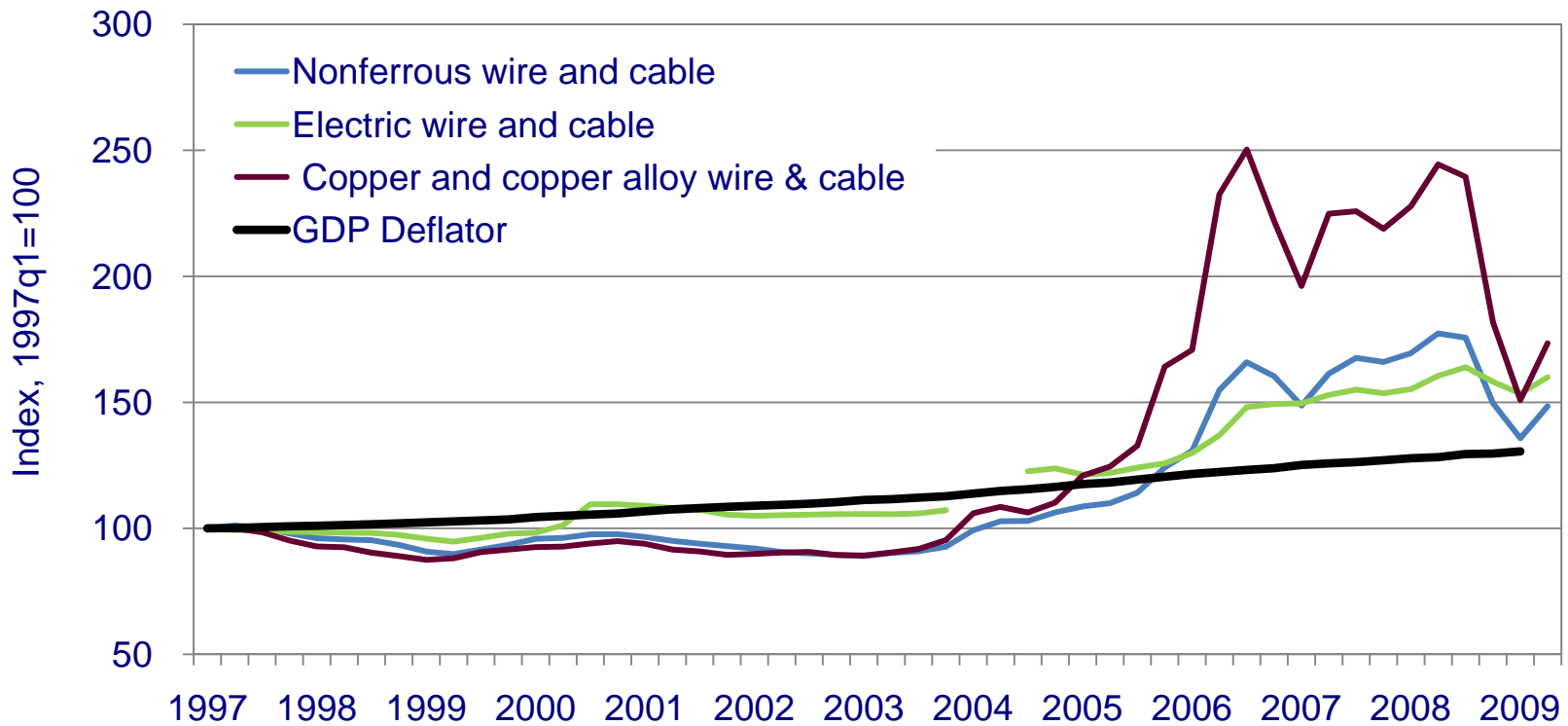
Common Empirical Adjustments (Costs) – Inflation Measures

Inflation for gas distribution service did increase relative to 2004, but year-over-year rates of change have flattened considerably.



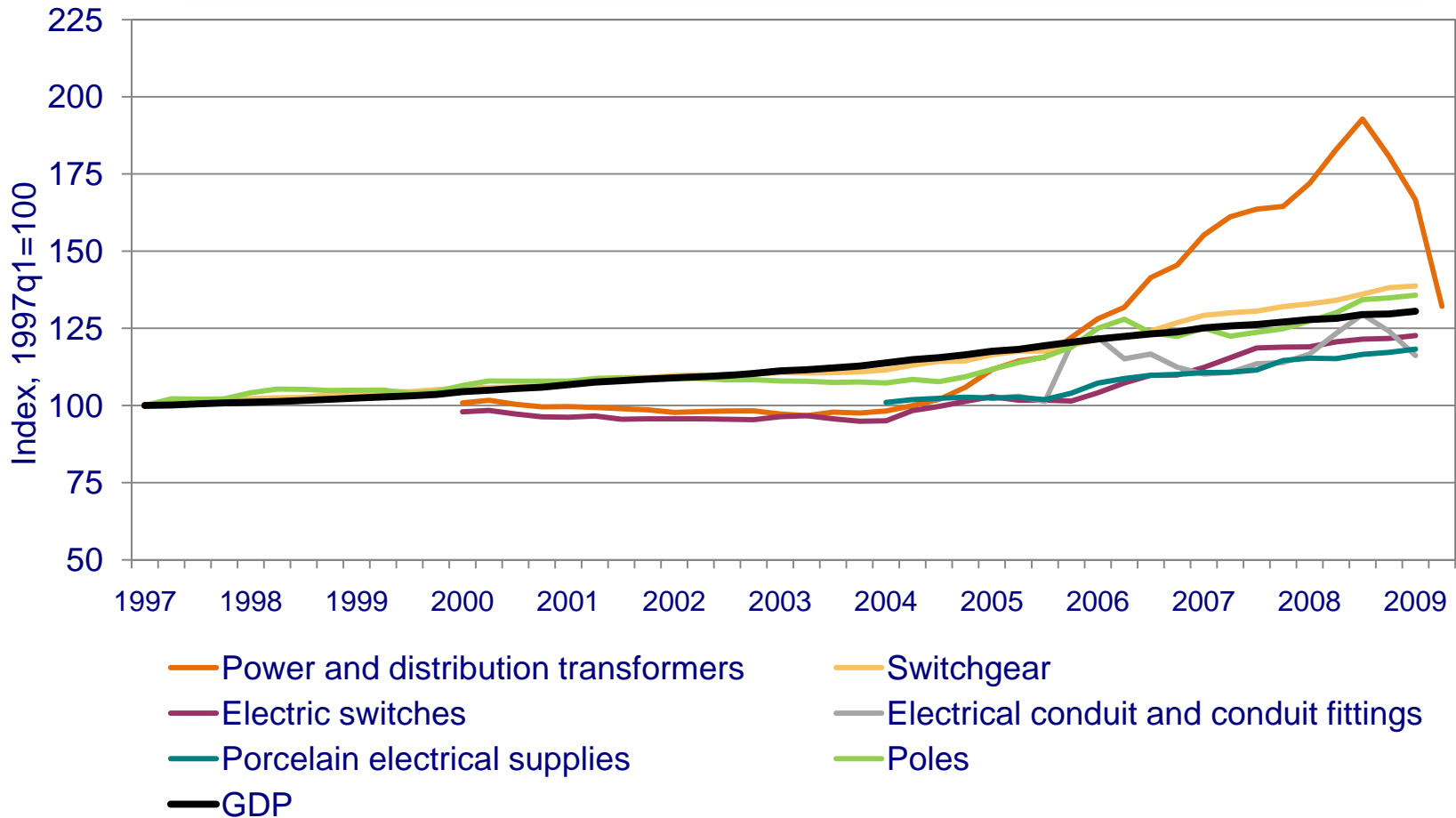
Common Empirical Adjustments (Costs) – Inflation Measures

Commodities important to the electric industry have seen copper wire by close to 30 percent from its high in 2006. Similarly, nonferrous wire has decreased over 17 percent in less than one year.



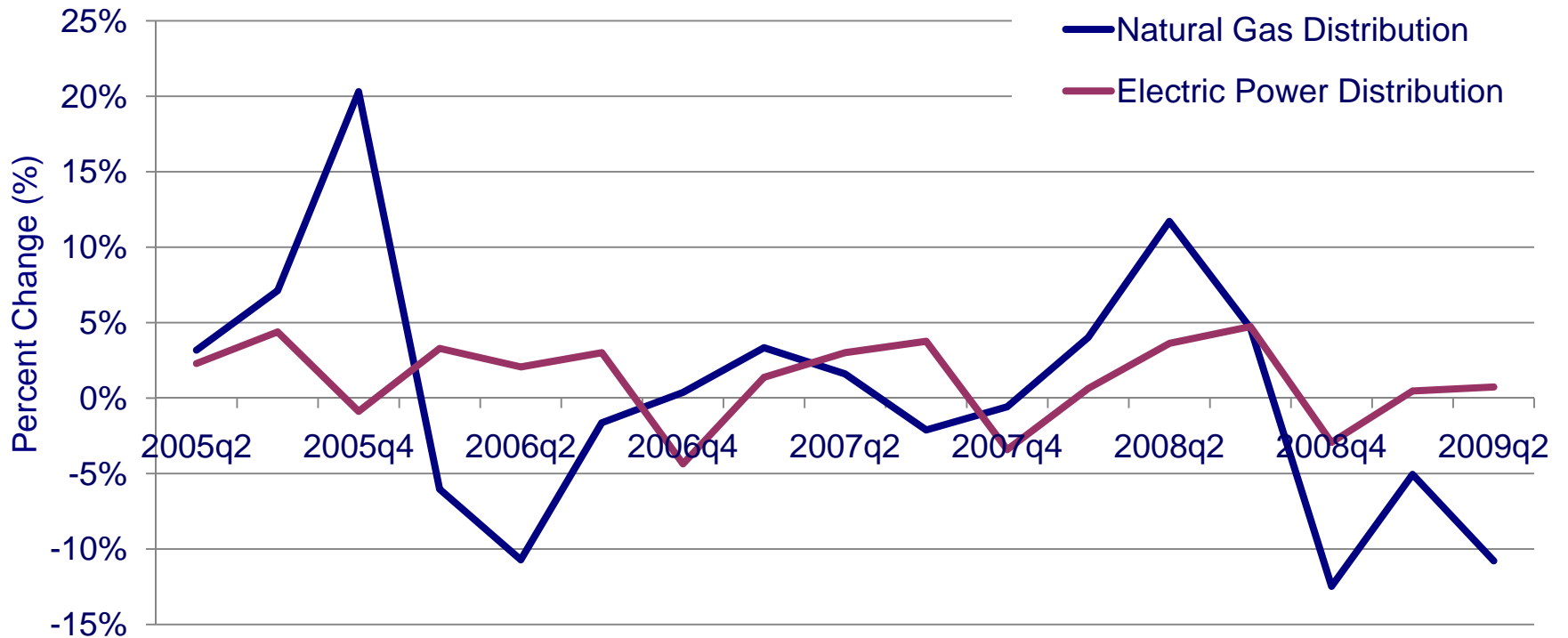
Common Empirical Adjustments (Costs) – Inflation Measures

The costs for other important electric cost components has actually been below the general rate of inflation.



Common Empirical Adjustments (Costs) – Inflation Measures

The annual rate of change for both indices has been falling.



Common Empirical Adjustments (Costs) – Inflation Measures

- **Caution needs to be assessed on inflation claims.**
- **Clearly past inflation, particularly at the commodity level, how that translates to the actual cost at the distribution level is more difficult to ascertain and will vary by utility.**
- **From empirical analysis perspective it is important to look at the right measures of costs and inflation that are often used very selectively.**
- **Benchmarking should be facilitated as check and to put requests into context**

5

Litigating forecasts and empirical analyses

Litigating forecasts and empirical analyses – Staff Objectives

Secure data, programming code, other input information. Request all variables be identified, variable transformations explained, identify all missing or excluded data (and rationale), and clearly identify and explain all assumptions.

Obfuscation is a dead-ringer for a problem. While software is usually commercially protected against distribution, no MODEL nor its OUTPUT is confidential.

Review sensitivities and diagnostics.

Research and verify relative to theory and practice.

Conduct independent analysis and where needed, supplement the record for your Commissioners: do not attempt to make your case through cross.

Litigating forecasts and empirical analyses – Regulatory Priorities

- **Confidence in forecasting reasonableness given current information and analysis goals.**
- **Base decisions on solid, tested and well-grounded methodologies and approaches: state of the art is not the same as best practices.**
- **Make sure decision is based upon independent output that can be verified – stay away from the black box.**
- **Decisions informed by important scenarios/sensitivities.**
- **Empirical consistency and accountability across proceedings and analyses (i.e., IRP vs. rate case)**

Questions, Comments, & Discussion

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