Cost of Service Regulation In the Investor-Owned Electric Utility Industry

A History of Adaptation

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Table 3. Selected Examples of Incentive Regulation

Jurisdiction and Company	Time Frame	Plan
CA—SoCalEdison	1998–2001	Price cap with ESM (distribution)
CA—SDG&E	1994–1997	Revenue cap (integrated utility)
	1999–2002	Price cap with ESM (distribution)
IL—All electrics*	1997–2007	
IA—MidAm	Through 2010	
DC—PEPCO (dist.)	Through 2007	Rate case moratorium/rate freeze
NY—RG&E	Through 2008	
Ohio—All electrics	2000 through end of MDP**	
PA—PECO (dist.)	Through 2006	
AL —APC	Ongoing	
CT—CP&L	2003–	Earing sharing mechanisms (ESMs)
GA—GPC	Through 2007	
LA—Entergy (NO)	2003–	

Sources: Sappington (2001) and authors' research.
*Includes ESM and benchmark for residential rates.
**Different utilities had different market development periods (MDP).

Another twist of fate during this period was a result of negotiation by a number of utilities to freeze their rates and in some cases to eliminate the existing FAC clauses as part of their bargain to restructure the industry. With fuel input prices stabilizing during this time period, utilities sought to minimize rate case expenses inclusive of fuel cost reviews. Fixing rates and eliminating fuel adjustments was also viewed as positive by consumer and government interveners and negotiated as part of the restructuring of the industry. As a result, the importance of the FAC in the revenue equation diminished in a number, but not all, of the states. This changing fuel market condition allowed state regulators to employ rate freeze incentives to keep customer rates more stable in this period.

4. Responding to Government Mandates

The Clean Air Act and other environmental laws required a number of actions on the part of utilities that involved the incurrence of considerable investment and operating cost expenditures. Two examples from this period come readily to mind: the scrubbing of coal fired power plants and the need to remediate old manufactured gas plant sites. Both of these situations created expenses that were not necessarily associated with any benefit to customers from the electricity supplied, but did provide a public good benefit of cleaner environments. What confronted regulators was another set of costs that were large, sometimes volatile, and outside of management control. State regulators reacted to this by employing adjustment clauses or surcharge (rider) mechanisms for the recovery of these special or extraordinary costs.[22] These mechanisms functioned as a separate means of cost recovery without the necessity of incurring a full rate hearing. The costs passed through in these mechanisms may be adjusted monthly or annually, and are typically subject to a prudence review, with customers receiving a rebate if imprudent expenditures were discovered. The changing nature of the economic environment was resulting in a larger number of categories of costs being addressed via "non-normal" processes and therefore not adequately treated within the typical rate case. The expanded use of

[22] For example, Pennsylvania authorized regulations that accelerated cost recovery through riders for capital costs to upgrade existing coal units, see 52 PA Code Ch. 57. In the case of coal tar remediation a number of states adopted rider mechanisms for the recovery of these costs.

rider or surcharge mechanisms to address these new categories of cost was a natural adaptation of the traditional rate case model.

E. Post Markets: Restoring Customer and Investor Confidence

The first decade of the 2000s would see a new set of challenges including a transition from stable prices to renewed inflation, a temporary return of energy growth that had not been seen since the pre-oil embargo days, and at the end of the decade, one of the worst economic down turns since the Great Depression. On the market front, competition experienced both major meltdowns in some states and continued success in others. This chaotic world presented regulators with a constant set of challenges and led to a renewed search for tools to improve their control over utilities in order to maintain cost effectiveness while meeting customers' needs. The continued mixture of markets and regulation resulted in a set of regulatory tools, including the creation of a set of codes of conduct to prevent cost shifting and cross subsidization between regulated and competitive services, the expanded use of single issue or post test-year rate mechanisms, and greater focus on procurement processes and pre-approval mechanisms to address the risks associated with large investment projects.

1. Markets and Meltdowns

Unfortunately, restructuring did not work as planned in a number of states. In California, the state which led the nation toward competitive retail electric markets, restructuring policy suffered from an over-reliance on spot markets. Utilities were required to sell all of their power into, and buy all of their load-serving power out of, the California Power Exchange (PX), which operated a day-ahead hourly spot market, holding auctions and matching bids for purchase and sale. From its inception in April 1998 until May 2000, spot prices were reasonably stable and on the order of $30/mWh. However, beginning in May 2000, average monthly PX prices began to escalate in dramatic and unprecedented fashion, peaking at over $300/mWh during January 2001. The central problem facing the utilities was that on the retail side of the business the rates were frozen. As a result, California utilities incurred huge costs which they were not allowed to flow through to retail customers, leading to the insolvency of the two largest utilities in the state. As a result the state was forced to step in and procure the utilities' "residual" power requirements that could not be met by utility-retained generation.

The melt-down of the California market, together with the December 2001 bankruptcy of Enron, sent shock waves across the country and the industry. For state policymakers, it demonstrated that there was political risk in electricity restructuring; for investors, that restructured markets presented new risks that were not present in the traditional regulatory bargain. Restructured utilities were, as the saying goes, "not your father's utility"; they were different in ways investors did not yet understand. As a result of this uncertainty many states continued to place on hold any further exploration of introducing retail competition into their utility markets.

The result was a great flight to safety, and not without reason. During the 1990s, utility operating environments had changed in ways that subjected utilities (and their investors) to increased uncertainty and risk. At the wholesale level, the divestiture of rate-based generating assets made restructured utilities far more dependent on wholesale purchases than ever before. Even utilities that remained vertically integrated have faced uncertainties about future state restructuring policy, leading many to rely on wholesale purchases rather than commit new capital to build rate-based facilities. At the same time, the development of competitive wholesale markets (open access transmission, market pricing authority, the introduction of spot markets) brought unprecedented volatility in energy prices, leading to major new uncertainties about the optimal timing of purchases. Fuel prices also became more volatile, at least in part because of declining fuel diversity, a legacy of PURPA and other legislation which continued the search for a silver bullet fuel to