



*Prepared Testimony of
Dr. John A. Anderson, Executive Director
The Electricity Consumers Resource Council (ELCON)
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I am John Anderson, Executive Director of the Electricity Consumers Resource Council (ELCON). ELCON is the national association for large industrial users of electricity. It was founded in 1976. We have members from a wide range of industries from traditional manufacturing to high-tech. There are many Michigan companies in the membership.

What I plan to do today is: first remind us why we need to move toward competition and choice; second present a brief status report on restructuring in the U.S., that is, basically, we are in a transition – one that will last a long time; third compliment both the Michigan Legislature and the Michigan PSC for their vision – and their careful implementation; and finally identify some of the things that Michigan has done right and wrong.

HISTORY:

In the “old days,” Industrial electricity consumers were offered a standard tariff or negotiated contracts subject to state regulatory approval. There was very limited choice – Customers were held captive to their local utility -- with a very wide range of rates charged to customers depending on their location. This environment produced mixed results. Some utilities were relatively efficient. But many others were not. Few were customer friendly.

“Choices” were limited: Customers could: consume or not consume at the regulated rate – and then pay the bill; self-generate or reduce consumption in other ways – or threaten to take

¹ ELCON, the Electricity Consumers Resource Council, is the national association representing large industrial users of electricity. It was created in 1976 as the federal government began to address electricity issues and industrial users realized that they could advocate policy in a more constructive manner by forming a united front. At the same time, industrial users hoped to create a technical resource for useful data and information that could be shared by member companies. ELCON, at the direction of its member companies, has focused on federal and state policies that affect the price, availability and reliability of electricity service. ELCON's overarching goal is to allow members to purchase electricity in a competitive manner, thus lowering the cost of power for industrial users.

such actions -- to either avoid purchasing or to try to negotiate a more favorable tariff offering; or participate in state rate cases to try to make rates affordable.

Utilities viewed regulators as their “customers”. They made money by lobbying legislatures and working regulators. Huge resources focused on process, not efficiency. Whatever regulators allowed in “rate base” was given roughly a 10-12 percent guaranteed rate of return. There was an incentive to “gold plate” to increase rate base and many reasons to inflate other costs. Regulators were outnumbered in efforts to hold costs down. No utility could be allowed to “fail”.

The prior monopoly model clearly was broken: Rates for electricity varied by more than an order of magnitude from one utility to the next. Utilities had no incentive to lower rates. Regulators simply could not (or did not) prevent the “too cheap to meter” nuclear plants and other cost overruns from hurting consumers.

In the mid-80’s ELCON saw the benefits of large, seamless, nondiscriminatory electricity markets with standard rules for all consumers. We believed then, as now, that “real” competition would produce the desired results, and we began advocating electricity competition. We viewed the electric industry as simply the last of the “old monopolies” to be subjected to a healthy dose of competition.

We believed then, and now, that competition would bring: lower prices – perhaps significantly lower prices relative to prevailing rates; technological innovation; new products and services; a customer focus by suppliers; as well as allow customers to control risk – that is, customers could select the level of risk that meets their needs, and manage that risk in manners that they choose. In our view, risk management is not done very well for customers by either utilities or regulators.

I emphasize, restructuring, to us, is NOT deregulation. Competition can be achieved in generation services, however, transmission systems must remain regulated. Transmission brings power from generation source to load centers. It is under Federal regulation (except in ERCOT). Multi-state transmission systems require Federal oversight while distribution systems remain regulated. On the other hand, distribution brings power from load centers to homes and businesses. Specific rates for distribution are set by state regulators. Finally, there is no connection between reliability and generation competition. Serious blackouts have occurred for years under the traditional “regulated” regimes.

At first, we were quite encouraged. We thought that competition was just over the horizon. By 2000, 25 States said that they were going to “restructure”. We were very excited with the stated intent, but we are very disappointed with the actual results. The problems were caused by both state regulators and legislators, prodded, of course, by those with very strong interests and tremendous resources – primarily the incumbent utilities.

We saw some glimmers of positive results. Lower prices – perhaps significantly lower prices in some areas. There was some of that in Michigan prior to Feb. 20. Technological innovation – as an example, Detroit Edison (and others) began investing in distributed energy

and small generation. New products and services were starting to become available. In some instances, utilities began offering ways to cut costs...although this was mostly in other states. A customer focus by suppliers -- at last, someone returns a phone call with an answer. Customers controlling risk: Customers have been able to look at long term contracts, hedging, or building own generation.

But, problems with other state activities have slowed the progress. California showed us what NOT to do. They had: inadequate capacity – in both generation and transmission; centralized power exchanges or pools with single-price auctions; a requirement that ALL power must be sold into and taken out of the power exchange (spot market); gaming behavior of suppliers and load serving entities – and the lack of appropriate market monitoring; generation divestiture & the absence of long term vesting contracts; retail rate freezes; poorly designed “provider of last resort” (POLR) services; and too much focus on the “right” market designs and not enough on eliminating barriers to competition and mitigating market power.

The failures of the implementation of flawed restructuring schemes imposed very significant costs. California had rolling blackouts and billions of dollars of costs due to a runaway market. Enron (and, to a lesser degree Dynegy) collapsed. Developing IPPs on a speculative basis became a questionable business model. Many utilities and power producers were downgraded – often significantly. Billions of dollars were lost as stock prices fell.

Where Are We Today?

We are in a terrible state of flux. In some places, the old regulated world is gone. But we are far from having truly competitive electricity markets. There is a lot of Balkanization by the states – and a lot of weird politics. One thing is certain – The need for competitively-priced electricity is as high as ever, particularly for manufacturers facing global competition.

What should we strive for? In my view, we need: large, nondiscriminatory markets based on bi-lateral contracts with many buyers and many sellers, not just one or two; adequate generation and transmission capacity; limited stranded cost recovery -- to only proven and net stranded costs and to a set period (Otherwise, you will always subsidize utility inefficiency); mitigation of market power of both generation and transmission; control gaming/interference from utilities; a division of transmission from generation; fair, non-discriminatory operation of transmission; and competition in technology (e.g., let competitors install meters, etc.).

We can learn a lot from the experiences from other states. I offer a few observations state actions from which we all can learn. I emphasize, this is not a comprehensive review, but rather an overview of some of the highlights. Specifically, I mention some examples in two states near to Michigan and two that are generally considered models: Pennsylvania, Texas, Ohio, and Illinois.

Pennsylvania:

Pennsylvania enacted HB 1509 in December 1996 allowing choice to 1/3 of all customers in 1999; another 1/3 in 2000; and the remaining 1/3 in 2001. Stranded costs: were identified in 1999 for each utility, recovery was through annually adjusted competitive transition charges (CTCs), and over a rather lengthy period of time for some utilities.

Pennsylvania was the most active state early in the process. But this all changed in mid-2001. The exercise of market power produced significant price spikes. Specifically, prices in the daily capacity credit market jumped from zero (or near 0) to over \$175. Market rule changes have prevented recurrences and capacity prices have been stable and relatively low ever since. But fuel price increases and increased numbers of hours with gas at the margin seriously dampened the enthusiasm of competitive suppliers. Additionally, long term price caps insulated customers from the high prices and marketers simply have a very difficult time beating the price caps.

The Pennsylvania PUC studied the situation and concluded there was reason to believe that anticompetitive or discriminatory conduct including the unlawful exercise of market power. Further, the threat of future recurrences of similar conduct is preventing retail customers from obtaining the benefits of a retail market.

However, the Pennsylvania Attorney General closed the case with no change to the policy. Many competitive suppliers then reduced their offerings or left the market completely. As of May 2003, there was only one competitive offer below the price-to-compare in the state.

Texas:

Texas enacted SB 7 that allowed all retail electric customers of investor-owned utilities (IOUs) to select their provider of electricity beginning on January 1, 2002. Distribution was still the right and obligation of the certified utilities. Customers < 1 MW received a regulated “price-to-beat” through 2007 – or until at least 40% of the customers in a class have switched. Customers > 1 MW are not eligible for a “price-to-beat”. All customers have access to “providers of last resort” “POLR”.

The infrastructure of Texas was significantly strengthened prior to restructuring. 47 new generation plants were installed between 1999 and 2002 leading to reserve margins > 35%. A significant amount of new transmission investment was undertaken to ensure that the transmission grid can accommodate the power flows needed to facilitate retail and wholesale competition. Retail providers, transmission and distribution utilities, and ERCOT have invested millions of dollars in computer systems to allow them to operate in the new competitive environment.

Unbundled rates were implemented on January 1, 2002. The excess generation, lower natural gas prices and implementation of the price-to-beat rate reduction mandated by SB 7 led to retail customers in Texas paying significantly less for electricity in 2002 – compared to the regulated rates in 2001. The Texas PUC estimates that RESIDENTIAL customers paid

\$902 million less in 2002 under the price-to-beat than under regulated rates in 2001. Retail Electric Providers (REPs) offered up to 14% additional savings off the price-to-beat to residential customers.

The Texas PUC estimated that RESIDENTIAL customers could have saved an additional \$636 million had they switched suppliers. The Texas PUC also estimated that COMMERCIAL and INDUSTRIAL customers paid approximately \$645 million less in 2002 compared to 2001. Much of this savings (esp. cities and other government entities) achieved these savings through successfully aggregating with other customers.

Many customers switched. The Texas PUC states that, as of September 2002, over 400,000 retail customers were taking service from REP's not affiliated with their local transmission and distribution utility. A majority of these customers are residential customers. By the beginning of 2004, nearly 40% of small commercial loads have switched to non-affiliated suppliers in the CenterPoint (CPE) and AEP Texas Central (TCC) service areas. Over 90% of all customers without a price-to-beat switched.

Texas has identified some technical problem areas in the restructuring program. Specifically: computer systems and electronic transactions, the establishment of new services, difficulties in billing – and in response time for paying accumulated bills.

The Texas PUC specifically identified broad issues that require resolution including: difficult financial conditions of various entities; the impact of stranded cost recovery – although some utilities were found to have NEGATIVE stranded costs based on a PUC-approved model, the PUC ordered those utilities to implement “excess mitigation credits” (EMCs) to prevent the over recovery of stranded costs; generation capacity adequacy; municipal registration of REPs; transmission constraints – especially related to wind farms; and wholesale market transparency.

More recently, the PUC adopted (in 2003) a rule to implement “Texas Nodal”. Currently, congestion is managed by zone, and the costs of intra-zonal congestion are “uplifted” to all “Qualified Scheduling Entities” (QSEs). Texas Nodal would replace the uplift with direct assignment of intra-zonal congestion costs. The rule also requires: A hedging mechanism, market mitigation measures, a day-ahead market to increase liquidity, and a capacity auction in September 2003 that resulted in significant increases for base load entitlement.

Several Stranded Cost True-Up issues are under re-evaluation. A District Court upheld the PUC's right to adjust book value if the utility has not mitigated stranded costs and to accrue interest beginning on the date of the final Order. However, the Court said that the PUC could not use a fuel cost over-recovery to offset stranded costs. The PUC also set schedules for 2004 cases for stranded cost true up using a market valuation method.

Ohio:

Ohio enacted SB 3 in 1999 – It: mandated a 5% rate reduction for all residential customers that the PUCO can remove if it restricts shopping – then a price freeze; established a 5-year

“market development period” (MDP) through 2005 (the MDP can be removed earlier if (1) 20% of customers shop or (2) the PUCO finds that competition exists); allowed aggregation by local governments -- the governments had to obtain the majority support of the community and under the “Opt-out” provision, customers were automatically enrolled with the community’s chosen supplier UNLESS they specifically refused; required the PUCO to determine stranded cost recovery; limited stranded cost recovery after MDP; specified that FERC approved transmission rates will define the transmission price paid by retail customers (both shopping and non-shopping) after MDP; and required RTO participation and a mandate to work with FERC and other states to address market formation.

Immediately following the enactment of SB 3, the North East Ohio Public Energy Council (NOPEC) formed an electric buying group that now represents more than 200 communities. This is the largest public aggregation of electricity customers in the U.S. Aggregation in Ohio has resulted in a very large number of switching customers. However, NOPEC has promoted incentive-based shopping credits and the creation of deferrals (regulatory assets) that are paid by all customers. This causes problems to the extent that the incentives create switching that is not sustainable.

In fact, the aggregation program clearly made Ohio the leader in switching. As of December 2003, aggregation statewide accounted for: 93% of all switching residential, 88% of all switching commercial, and 20% of all industrials. FirstEnergy had the highest regulated rates – and the highest switching. Cleveland Electric had over 60% of all customers switch; Ohio Edison had over 30%; and Toledo Edison had about 40% switch. Nearly 19% of all customers had switched. Much, but not all, due to aggregation

Transition plans were filed in 2000 by each utility. FirstEnergy’s plan had a negotiated settlement provision that makes available 1,100 MW of capacity to marketers to serve load in FE’s territory. Rate stabilization proposals are now pending. Dayton Power & Light’s has been approved. It allows unbundled generation prices for non-switching customers in effect through 2008. AEP, Cincinnati Gas & Electric, and FE also would affect default service prices through 2008. Mon Power has contested on constitutional grounds (taking – and are confiscatory) the rate caps during MDP.

Although there is a lot of switching in Ohio, there is a lack of real customer choice. Electricity prices remain frozen during the MDP. The PUC has yet to design final rules for default service once the market development period ends. The “Opt-out” provisions in the aggregation program have caused some problems for businesses. Some haven’t been able to respond in a timely manner and are unknowingly switched. The shopping credits have also caused problems.

Illinois:

Illinois enacted HB 362 in October 1999. Retail access for residential began on May 1, 2002. But the law mandated a rate reduction and rate freeze until 2007. No residential customers have switched. Some larger customers have switched. But roughly half of them chose the “Power Purchase Option”, an unbundled, market-based generation option that non-

residential customers subject to transition charges must be offered and is supplied by the incumbent utility.

The ICC issued orders in March 2003 that: established new delivery service rates for ComEd; established new market value index procedures for ComEd, IP and Ameren that modify the market value determinations, offer multiple year market value lock-in options, and revised ComEd's Rate HEP-hourly energy pricing which will become the provider of last resort bundled rate for customers no longer eligible for other bundled service from ComEd.

The ICC emphasized that the wholesale market is undeveloped. Holding companies own or control most of the generation capacity in each service territory. With generator ownership highly concentrated, there is little incentives for independent generation, and a lack of transparency.

The ICC identified impediments to competition including: inadequate transmission with utility affiliate ownership of most of the generation giving little incentive to expand transmission and the rate freezes hinder recovery of transmission expenditures; the existence and volatility of transition charges – based on lost revenues; the “Power Purchase Option” (PPO); reciprocity requirements; and a lack of supplier interest in serving residential customers.

The ICC concludes that: “The absence of a dependable and transparent regional wholesale power market is directly related to the lackluster growth of retail competition.” The ICC further notes: “...even under the conditions of higher bundled retail rates and no transition charges, a retail market will have little chance of succeeding unless the wholesale market is reasonably competitive at that time.”

The ICC made 10 recommendations:

- Require utility membership in properly designed and configured RTOs
- Readdress the functional separation issues between regulated utilities and their unregulated affiliates
- Allow new transmission investments on the basis of the promotion of competition
- Exert greater oversight of utility asset transfers
- Require competitive bidding for bundled supply
- Permit the ICC to set non-discriminatory stand-by rates
- Do not permit utilities to reject ICC market value decisions
- Permit electric suppliers to use telemarketing-based customer enrollment methods
- Eliminate the 24-month ban on customers returning to delivery service
- Consider implementation of municipal aggregation

How Does This Apply To Michigan?

Michigan recognized the need for change in 1997. Michigan electric rates were the highest in the Midwest. The high rates hurt business development. As a specific example, North

Star Steel chose Ohio over Michigan. Michigan utilities were not building new generation or transmission. Transmission constraints limited the amount of power that could be imported into the Michigan peninsula.

The Legislature responded with PA 141 in 2000:

- Utilities could “securitize” and recover stranded costs
- Customers got the right to shop
- Residentials got a 5% rate reduction
- Increases in transmission were mandated
- Independent generators got the promise of competitive markets

PA 141 was a compromise supported by all stakeholders. All stakeholders believed that the act was balanced. In fact, Anthony Early is quoted in his Annual Report of January 31, 2001: “The drafters of our legislation paid attention to the early warning signs in California and established safeguards that will provide for an orderly transition to competition.”

Utilities immediately received benefits. The MPSC approved \$1.7 billion to cover the costs of DTE’s Fermi and other high cost plants. Ratepayers will pay for these costs for 14 years. Rates for consumers were frozen, despite the fact that DTE had a pending rate cut of \$108 million per year which was later dismissed.

There were several results of these actions: independent generators built \$2.7 billion of new, non-utility generation – 10-12% of Michigan requirements; consumers slowly began to shop for alternative power sources; and “Alternative Energy Suppliers” (AES) in Michigan now number 25 – 30.

Throughout this time DTE maintained both its credit rating and stock price. In fact, a January 14, 2004 Morning Star report gives DTE a 5 star rating. Morning Star concludes: “...we believe DTE is a good company, with an enviable set of regulated and non-regulated assets and a healthy balance sheet. We would gladly buy into it at the right price.” Morning Star says: “Our fair value estimate for DTE is \$60 per share. We have taken a very conservative approach to arrive at this estimate because of deregulation, the uncertainty surrounding the rate increase, and the pending extensions of synfuel tax credits.”

In sum, Michigan: has avoided market power prone power pools; allows long term contracts; implemented a conservative approach that has allowed markets to develop carefully; took steps to spur new generation; and took steps to spur new transmission. The MPSC says: “None of the conditions that caused the ‘California-style blackouts’ exist here in Michigan.”

Michigan has taken some steps to assure success: created a market of many buyers and many sellers; limited stranded costs to only proven and net stranded costs; limited stranded cost recovery to a set period; tried to limit market power by upgrading and divesting the transmission system and joining MISO; and encouraged separation of generation from transmission (and utilities did it VOLUNTARILY and pocketed part of the proceeds).

Unfortunately, Michigan prevented anyone other than utilities from switching out meters. DTE today is well behind the 45 day policy of the state to make switches.

Michigan has implemented choice (mostly) right: utilities are still quite healthy. New generation was built, helping reliability. Prices are down overall – but not enough. There are 28 certified AES's in Michigan serving approximately 12% of the electric non-coincident demand..

However, there is still work to do. Michigan electric rates are still high by regional standards. Uncertainty in MPSC decisions causing problems. For example, the February 20th decision changed rules fairly dramatically. However, they can be revisited by commission.

Michigan has not made fatal mistakes. Michigan didn't give utilities undue stranded costs; didn't extend stranded cost payments; didn't constantly change laws and policies knowing that markets demand consistency to develop; didn't fixate on one segment of market; and didn't constrain anybody's ability to choose. Michigan recognized that bigger markets are better!

I thus compliment Michigan for its vision and implementation. You have started well. I encourage you to stay the course. Allow the MPSC to administer PA 141 as was authorized in the original Act.

Conclusions:

Competition is better than regulation in the right marketplace. It sends right price signals. It encourages new generation at proper times. It encourages innovation. It brings about better service. Markets must be designed correctly. California has shown us what not to do. By and large, Michigan is a good example of what to do. Don't change the rules today.