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North East Arizona Energy Services Company (nea_esco)
HC30 Box 2A
Concho, AZ 85924
(928) 587-6378

Utility Commission
Corporation Commission
State of Arizona

Arizona Corporation Commission
DOCKETED
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Response to Staff Report
In the Generic Electric
Restructuring Docket
E-00000A-02-0051

E-00000A-02-0051
E-01345A-01-0822
E-00000A-01-0630
E-01933A-02-0069
~~E-01933A-98-0471~~

Dear Sir(s):

Please find enclosed a greatly reduced version of the Generic Restructuring Docket. I have reduced it to 22 pages and highlighted to bring into focus what I think is a main string of thought. I very much hope that this attempt to enjoin you in a critical discussion is appreciated for its appropriateness.

When reading the docket for instruction on "what was happening" I discovered within the Docket itself what I think are several points of redirect.
Namely:

1. There is an immediate need to take action because the adequacy of our available supply of energy for today's needs are being challenged
   - Existent transmission constraints of electrical current
   - Inadequate supplies of natural gas for current and proposed use
   - "Dirty" generators being used in "must run" situation

2. Actions that have been taken to date counter spoken intent
   - Cheap energy (as regulated by the Commission) equals a field in which competition cannot take root
   - Dependency on "foreign" (other than Arizona) sources is dangerous, e.g.; California crisis, etc.

3. Certain actions being proposed are "affordable" and if done on large enough scale, can be truly effective in creating a self-reliant, cheap, clean, energy future.
   - Impose a "surcharge" or "addor" to the price of electricity. This can be done because the "hard cost" has been artificially kept low.

     Impose this charge broadly, Arizona Wide.
     Impose this charge based on an index of what source was used to produce the electricity at the generation site.
     This charge would be imposed on the retail level because of the clarity of authority (wholesale authority FERC not involved).

We can find success now by enacting this while encouraging competition..

- Require that all billing on the retail level have a "truth in label" section where it discloses all sources of energy as a percentage of total energy on line and show the appropriate charge relative to that energy source (based on "Externalities" as referenced in DOE/ Duke University Report or our own 1992 Externalities Report, or Commission Ruling.)
- DISCLOSURE will encourage a higher awareness of our total "Social Cost" choices. Hopefully this will lead to greater social responsibility (consumer CHOICE).
- Monies obtained from this "surcharge" would be put into a state-wide fund, available to all who purchase clean renewable energy generation technology (comparable to what California has had—approximately 50% of the actual cost as "rebate").
- These actions will help "level the playing field" mentioned by several participants.
- We can open our eyes to the true total "Social" costs involved in our actions. When these total costs are calculated in our attempt modify our future by comparing and insisting on "cheap is better", at least see "cheap" relative to "real" and not just "hard".
- These suggested actions above should not preclude the continuance of the other renewable energy incentives; e.g., EPS, net metering, etc.)
- The Environmental Portfolio Standard (EPS) could be used as a "template" by expanding its authority and breadth.

Thank you very much for your attention to this matter, not just for what you've already done (which is massive), but for what you are doing today. Please find the enclosed attachment. Thank you again.

Larry E. Bell
President
North East Arizona Energy Services Company

cc: Department of Energy, Golden Field Office, Million Solar Roofs
Million Solar Roofs Western Region Office, Seattle, WA
Greater Tucson Coalition for Solar Energy
Million Solar Roofs State Partnership, Phoenix
Million Solar Roofs SRP Partnership

Excerpts from Staff Report
In the Generic Electric Restructuring Docket
E-00000A-02-0051
March 22, 2002

These are "clips" or "snippets" from a 234 page Report. No editing of words have been done, effort has been made to maintain total contextual relevance by keeping the entire page, otherwise please scan to read RED.

In the small customer market, the profitability of retail market entry has generally not been sufficient to overcome the acquisition and aggregation costs for new suppliers, who have had to compete with the incumbent utility or other designated standard offer provider. Few suppliers have entered the small retail market aggressively, and retail customers have tended to remain with standard offer service.
As noted above, much depends on the relative prices of standard offer and market suppliers. The general problem is that shopping credits have been inadequate to make competitive service attractive. Putting it another way, commissions have made every effort to keep standard offer service prices down, and this has made the market unattractive to alternative suppliers and has given customers little incentive to switch.

It is now being recognized that the shopping credit must be significantly higher than the wholesale energy price if it is to be sufficient to attract customers to the competitive market and provide suppliers a margin of profitability. First, it needs to take into account the (often low) load factor of small customers, i.e., needs to include a cost to account for peak period usage and installed generating capacity. Second, a retail adder is required to cover marketing and other retailing costs.

Even in the states where retail competition has been deemed a success, stranded cost recovery has sometimes undermined customer migration to the competitive market. In Connecticut, for example, a stranded cost charge which is in effect an "exit fee" reduces the effective shopping credit.

For customers, is the cost associated with learning how to shop and actually shopping sufficiently small, relative to the expected benefits, that customers would want to shop.

The pro-competition view ignored this issue, assuming that customers would be eager and willing to shop for a good deal or for innovative services. However, states had doubts about customers' ability and willingness to shop, and put standard offer service in place to provide customers with a reliable and reasonably priced fallback for electricity as an essential service. In practice, the continuation of full utility service by the incumbent utility, including standard offer service at favorable prices negotiated by state commissions, has thus far proved fatal to retail competition for residential and small commercial customers in most states. In addition, many small customers do not have the time, wherewithal, or interest to shop for a product that never captured much of their attention in the first place.

The Federal Energy Regulatory Commission is only gradually coming to grips with the two principal features that are needed to make a wholesale generation market workably competitive and reliable. The first is willingness and ability to root out horizontal *market power* by breaking up suppliers and removing barriers to entry. ...
The second principal feature that must be put in place under the aegis of FERC before the generation market can be competitive is a well-designed RTO that can effectively monitor the wholesale markets, monitor and control transmission, price transmission services fairly and in such a manner as to broaden the market, design the expansion of the transmission system in coordination with power plant construction to avoid bottlenecks and supply disruptions, and ensure non-discriminatory transmission access to new generators.

The Commission's Environmental Portfolio Standard (EPS) acts to promote the use of renewable energy sources such as solar. Without the EPS, it is doubtful that these sources of generation could compete (based on cost) with traditional generation sources.
In order for distributed generation to become a significant source of generation, interconnection standards and processes need to be established.
Over the years, the Commission has approved various cost recovery mechanisms and other procedures for demand-side management (DSM) as an incentive for utilities to consider cost-effective DSM instead of additional supply sources.

We see two major defects in Arizona's current wholesale market structure. One is that incumbent utilities have large shares of the generation (and transmission) market and, if that market is restructured, they would likely be in a position to exercise market power, by raising prices above competitive levels and/or discouraging new entrants. In such a situation the incumbent utilities would be reluctant to work towards relieving the transmission constraints that enhance their market power. Second, transmission constraints limit generator access to Arizona load centers. Third, we believe that the ISO/RTO arrangements at this time are inadequately developed to ensure an open, competitive, and stable wholesale market. The cure lies primarily with the FERC, which is attempting to move forward on these matters. The development of WestConnect under the aegis of FERC will be critical in this respect.
In light of these three defects, we believe it would be prudent for the Commission to wait before requiring jurisdictional utilities to place substantial reliance on the wholesale generation market.

There are transmission constraints both inside and outside Arizona that currently impede competitors reaching Arizona customers during summer peak hours. These constraints were reported in Staff's Biennial Transmission Assessment revised July 2001 and adopted by the Commission. The report established that three geographical load zones (Phoenix, Tucson and

Yuma) are transmission import constrained at peak load conditions. Generation internal to these load zones "must run" at peak load conditions to avoid system overloads and voltage problems for outage of critical lines.

Firm regional transmission capacity for competitive Electric Service Providers to import power to Arizona retail customers is also very limited and only available on selected transmission paths.

Is the natural gas pipeline infrastructure adequate to support all proposed new gas-fired generation plants? How many plants can it support?

The natural gas infrastructure in Arizona at this time largely consists of El Paso Natural Gas Company's (El Paso) northern and southern interstate pipeline systems and associated laterals. The Transwestern pipeline in northern Arizona also serves a small amount of Arizona's natural gas needs. Currently there are no appreciable instate natural gas production, natural gas storage, or liquid natural gas facilities in Arizona. Therefore, natural gas consumers in Arizona, whether residential or power generating in nature, rely on the on-going flow of natural gas on the interstate pipeline system to meet their service needs.

There is a general uncertainty regarding pipeline capacity availability for shippers on the El Paso pipeline system. The rights, obligations, and needs of shippers and El Paso are being disputed in a number of proceedings at the Federal Energy Regulatory Commission (FERC). At this time it is unclear how or when the disputes regarding pipeline capacity will be resolved. However, it is clear at this time that during periods of high demand, the El Paso system is unable to fully meet the needs of its existing shippers. During periods of relatively low demand on the interstate pipeline system, it appears that the system is generally able to meet the needs of its shippers. This situation exists at a time when few of the new natural gas-fired generating units are yet operational. As additional gas-fired generating units come on-line in Arizona and other southwestern states that utilize the same pipeline systems, the inability of the existing pipeline system to serve all customer demands will become increasingly apparent.

El Paso has failed to address the growing demands for natural gas transportation in Arizona and the Southwest. New generating facilities appear to be relying on a number of possible sources of pipeline capacity for their facilities, including: use of existing contract rights, acquiring released pipeline capacity from other shippers, purchasing rights on new pipelines or pipeline expansions, and swapping of gas supplies on different pipeline systems. In the long term, market players are likely to build additional pipeline capacity and/or natural gas storage capacity to serve additional demand for natural gas in Arizona and the Southwest. However, it is unclear at this time how well the availability of additional pipeline capacity in the future will coincide with the additional natural gas demand of the new generating facilities in the next few years. The on-going uncertainty regarding existing shippers rights on the El Paso system has made it difficult for both shippers and potential capacity expansion developers to accurately gauge what the demand/need is for additional capacity. Most new gas-fired generating units in Arizona are located near El Paso's southern pipeline system, and this is likely to be the area of greatest concern regarding the shortfall of interstate pipeline capacity, although several recently announced pipeline projects may at least partially address the shortfall.

Does the transmission and distribution system facilitate or deter --
a. the development of renewable energy technologies?

Current transmission and distribution system structures deter the development of renewable energy technologies in three significant ways. First, on the local level, the small size and often remote locations of renewable generators mean that they are not directly connected to the regional bulk power system and often have to pay a distribution utility tariff in addition to the regional transmission tariff. Second, interconnection procedures in many regions do not provide streamlined procedures for interconnecting small generation units that have virtually no impact on the bulk power system. Third, the wholesale markets administered through tight power pools do not accommodate the small size and often intermittent production output associated with most renewable generation, such as wind, hydro, and solar. Until these barriers are addressed and a level playing field is created, renewable generation technologies will be at a competitive disadvantage.

b. the development of distributed generation?

The same issues discussed above regarding renewable generation also apply to distributed generation. In addition, local distribution utilities have difficulty integrating and accommodating the power flows of distributed generation that may operate only during peak load periods. One solution to this difficulty is to require the distribution utility to purchase, through bids, distributed generation resources that it then operates.

c. the development of demand-side management and energy efficiency?

Although integrated resource planning in the 1990s quantified the significant benefits that energy efficiency, conservation, and load management can provide to distribution and transmission systems, there are very few mechanisms developed that capture these benefits. As mentioned earlier, Vermont has implemented a statewide efficiency utility that is supported through a systems benefit, or wires, charge. Alternatively, the RTO entity could provide incentives for demand-side programs based on the benefits to the bulk power system; however, the RTO may not be in a position to offer incentives for the distribution system benefits associated with DSM measures.

In a vertically integrated utility model, what incentives (regulatory, financial and ratemaking) exist for the expanded use of renewable energies?

In the simplest terms, in a vertically integrated utility model the incentives to expand the use of renewable energy exist in the form of approved generation plants that qualify for rate base treatment. If a renewable generator is easier to site and easier to include in rate base than a fossil-fueled plant, then the utility will favor the renewable generator even if its production costs
are higher.

In many states, there are standards or goals (some voluntary, some mandatory) for expanding the use of renewable resources. To the extent that these standards and goals can only be met through the addition of new renewable generation units, then an incentive is in place that will encourage the expanded use of renewable resources.

There are currently only a few explicit incentives for use of renewables in the vertically integrated utility model. Some of the most commonly adopted explicit incentives in the nation are portfolio standards for renewables, system benefits charges, and renewable energy funds. However, the Commission, in Decision No. 57589, the Commission's 1991 Integrated Resource Planning decision, found that environmental costs and other externalities must be considered by resource planners in making informed decisions about new electric energy resources and services. The Commission established a Task Force to identify and quantify environmental costs and externalities. The Externalities Task Force met during 1992 and published the "Report of the Externalities Task Force" in December 1992 (Docket No. U-0000-92-035). For the purposes of the Commission's efforts, an externality was considered an impact on society not accounted for by the producers or consumers of electricity in the course of production or consumption of electricity.

In 1994, Staff commenced development of draft rule amendments to include externalities in the Commission's Resource Planning rules (R14-2-701 through 705). Later in 1994, after California published its Blue Book on Restructuring and Arizona decided to move toward consideration of electric competition, the rule-making effort ended. The Commission later suspended portions of the Resource Planning rules.

If Arizona were to decide to continue with a vertically integrated utility model, the externality effort could be included in Resource Planning rules. Alternatively, the Power Plant and Transmission Line Siting Committee could use externalities as a way to evaluate potential power plants before making recommendations on Certificates of Environmental Compatibility. Since many renewables are generally less environmentally damaging than conventional, fossil fuel generators, the consideration of externalities could act as an incentive for renewables.

There are two commonly mentioned "incentives" for the development of renewable energy resources in a competitive market: special retail products and renewable portfolio standards.

Special retail products refer to efforts by retail competitive suppliers to market products specifically tailored to consumer preferences. For example, Green Mountain Energy Resources (GMER) provided three distinct products to California consumers: a 60%, 75%, and 90% renewable-based retail electric service. As consumers signed up, GMER committed to expand its contracts with renewable energy generators to maintain the advertised percentage of renewables.

Another approach to special retail products is a disclosure label that states, among other information, the resource mix of fuels that were purchased by the retail supplier. The thought is that consumers may want to switch to a supplier who provides a greater percentage of renewable resources in its fuel mix, thereby encouraging the development of renewable resources.

The second general incentive program for renewable resources is a renewable portfolio standard (RPS). Enacted either through state legislation or by commission rule, an RPS requires each retail supplier to have a minimum percentage of renewable resources in each product that it provides to consumers. Some RPS programs, such as the Environmental Portfolio Standard in Arizona, also mandate a specific percentage of "new" renewables or specific types of renewables.

There are also some federal and state tax credits that are available. One potential incentive would be the standardization of distributed generation interconnection procedures and agreements. Simplification of procedures and streamlining of interconnection hurdles could significantly improve the potential for new renewables development. Net metering (or net billing) laws or rules would encourage customers to buy and install renewables on their own property. Renewable leasing programs or lease-to-buy programs would allow customers to utilize renewable systems even if the customer did not have the capital to install his/her own system.

One disincentive for expanding the use of renewable resources in the traditional model is the generally higher production costs currently associated with many renewable energy resources. In a regulatory climate that focuses on just low cost, the higher prices of renewable energy resources will often act to exclude them from consideration. While there are well-documented case studies to the effect that traditional low-cost resources are receiving significant subsidies or cause significant collateral cost impacts that are shifted to society as a whole (such as air pollution), traditional regulatory and ratemaking policies tend to discount or completely ignore these "societal costs."

There are financial disincentives for cooperatives that might be interested in incorporating renewables in their generation mix. Since cooperatives rely on RUS and CFC for financing, which require the least-cost generation resources, renewables that are more expensive than fossil fuel generators do not even get considered.

In a competitive electric market model, the lowest delivered cost per kWh is the driving force in decisions to add new generators. If renewables appear, in the short run, to be more expensive, they will not be considered, even though over the long-run, when considering potential fuel cost increases or fuel availability risks, the renewables may be a better long run choice. Many renewables are very capital intensive, but have little, if any, ongoing fuel costs. (The wind and sun are free.) On the other hand, many conventional generators, such as gas turbines, have extremely low capital costs, but also have the potential for extremely high-cost fuel impacts over time.

Under the vertically integrated utility model, what incentives exist to build newer plants that are less damaging to the environment to replace older, dirtier plants?

Very few incentives exist. Least-cost dispatch has always been the key in a vertically integrated utility model. Rate-basing of plants by the state regulatory commission provides the financial incentive for building new facilities. The commission may be able to mandate the construction of cleaner new plants, or at least can agree to rate-basing of those newer, cleaner plants. The new plants may render the older facilities uneconomic, but a further financial incentive may be needed, namely an agreement by the commission to allow continued recovery of any remaining depreciated book value of the older facilities.

Under the competitive electric market model, what incentives exist to build newer plants that are less damaging to the environment to replace older, dirtier plants?

Very few incentives exist. Similar to the response to Question #2 above, special retail products or a portfolio standard -- in this case related to low pollution or minimal environmental impact specifically – could provide an incentive.

Although some would say that the next generation plants will be more efficient and cleaner than the older plants, this isn't necessarily true. At the same time that a dozen or more gas-fired turbine plants are being built or proposed in Arizona, Tucson Electric proposes to build two new coal plants. It is entirely possible that the two new plants could partly or completely displace older, simple cycle gas plants that are "cleaner" than the new coal plants, at least in terms of the volume of air pollutants. There are no explicit incentives for "clean" plants, only incentives for the operator who can operate his plant at a lower cost than his competitors.

Under the vertically integrated utility model, what disincentives (regulatory, financial and ratemaking) exist to build newer plants that are less damaging to the environment to replace older, dirtier plants?

If older, dirtier plants are already receiving cost recovery in rate base, and there is uncertainty about the rate-basing of new facilities that may constitute "excess capacity," a utility would have a financial disincentive to build the newer facilities without a green light from the legislature or commission. Likewise, if reliance on energy from newer plants involved departure from least-cost dispatch, a utility would have a financial disincentive, unless it received regulatory approval.

If older, dirtier plants are still operational and the plants' fixed costs have essentially been "paid off," they can still continue to operate and compete against newer, cleaner plants that need to charge prices to reflect fixed costs, variable costs, today's financing costs, and a competitive profit margin. In a state, such as Arizona, where the older plants have such an advantage, new competitors will not voluntarily install any pollution improvement if it will make their electricity less competitive.

Under the competitive electric market model, what disincentives exist to build newer plants that are less damaging to the environment to replace older, dirtier plants?

The disincentive is that the owners of the existing, dirtier plants, which may already be fully depreciated, will have no reason to build newer, cleaner plants, unless those plants are significantly less costly to operate than the older plants of their competitors. Since the environmental costs of the older, dirtier plants are not paid directly by the plant operators, ***as far as the operator is concerned, those environmental costs don't exist.*** Since price is king in the competitive model, any pollution-reducing extra costs would be seen by plant operators as making their product more costly, and, therefore, less competitive.

While a state may set rates for retail transactions, it may not set rates for wholesale transactions. Narragansett Elec. Co. v. Burke, 119 R.I. 559, 381 A.2d 1358 (1977), cert. denied, 435 U.S. 972 (1978). The task of setting wholesale rates belongs to the Federal Energy Regulatory Commission (FERC). The rates set by FERC can either be preemptive or nonpreemptive. When the transaction is nonpreemptive, the courts have recognized the authority of states to limit a utility's ability to recover FERC-approved rates. When the wholesale transaction is preemptive, FERC approval of the wholesale rate preempts the States from taking any action that limits the pass through of the wholesale costs. The crucial differences between the two lines of cases involve the factual circumstances of the transactions. The second line of cases involves "trapped costs." Although the Supreme Court has not defined the phrase explicitly, its decisions indicate that a "trapped cost" occurs when (1) FERC issues a decision requiring the purchasing utility to take a particular action, while (2) the state sets the utility's rates as if the utility had made a different choice
Staff understands that, as a general matter, the divestiture or transfer of assets of vertically integrated utilities would result in loss of jurisdiction by the Commission over the divested entities and a loss of jurisdiction over wholesale contracts between the utility and the divested entity. The transfer of assets to a functionally separated division of the utility within the same corporation, as provided for by the Virginia commission, would not appear to result in a loss of jurisdiction by the Commission.

Yes, the generation price is likely to fluctuate with the price of natural gas. An orderly, competitive gas market would contribute to electricity price stability. So would fuel diversification by electricity generators.
Price volatility and inflation are significant risks associated with a competitive market/

Residential choice is probably *not* a real option at the present time, given the lack of suppliers willing to service small customers.
It is conceivable that the small customer market could open up in time, and bring some benefits to those customers. Factors that could favor customer choice include the development of lower-cost advanced meters and interactive load controls for small customers, and greater seasonal and daily variations in wholesale market prices, which could together make real-time pricing economical. Another factor could be the development of customer aggregation, which would reduce customer acquisition costs for marketers.

Staff must consider what is in the best interest of Arizona's consumers while affirming that we support a properly functioning competitive market. In doing so Staff recognizes that competition potentially could afford three principal benefits to Arizona's consumers: price, choice, and innovation. Staff believes that, if the Commission chooses to remain committed to competition, the Commission should structure the transition to maximize these three potential benefits and to recognize an appropriate balance between them. Specifically, Staff does not believe that price benefits should be sacrificed in order to encourage consumer choice.

Adjustor mechanisms for standard offer service. At least one Arizona utility will be implementing an adjustor mechanism for its standard offer rates in the near future. In light of the problems with the development of a competitive wholesale market discussed in this Staff Report and in APS' request for a variance, Staff believes it would be appropriate to reassess the need for such an adjustor mechanism.

Shopping credits and unbundling generally. The adequacy of the shopping credit (the cost a customer would not pay to their UDC if they take generation service from a competitor) has been identified as being highly significant in the development of a competitive retail market. Staff is opposed to imposing artificially high shopping credits in order to give an artificial boost to competitors. However, the shopping credits and unbundled rates now in effect, such as they are, should be examined in order to determine whether they are set at levels that are artificially low...

For customers, is the cost associated with learning how to shop and actually shopping sufficiently small, relative to the expected benefits, that customers would want to shop.

APS states that it largely depends upon the individual customer, although for large customers it is more likely that the costs of shopping are outweighed by the benefits. For small customers, because electricity bills have been declining in recent years, it is less likely that small customers will want to shop for electricity.

TEP states that it believes the cost of shopping for residential and small commercial customers has been an impediment to their participation in the competitive market. Large commercial and industrial customers have more resources to evaluate the benefits they would receive from participating in the competitive market.

AUIA states that unless customers are upset and dissatisfied, few will shop for alternative providers. An AUIA survey found that no customers will switch for less than 10 percent savings and many would not switch for less than 20 percent savings

AES states that the potential savings from competition have been limited for Arizona customers because of the requirement for customers to pay off the utilities' stranded costs from past investments in power plants through a competition transition charge (CTC). The primary reason for the failing retail market in Arizona is that administratively set shopping credits are not calibrated to the market price for electricity. But in TEP's area, it is difficult for customers to make a price comparison because of the way the shopping credit is recalculated quarterly.

Electric Cooperatives

AEPCO, Southwest, and Sierra state that the Commission's legal workgroup had authored a volume of work which in large part answers these questions. AEPCO, Southwest, and Sierra further state that the Commission cannot authorize market-based rates and individually negotiated outcomes without amendments to Article 15 of the Arizona Constitution.