BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF A REPORT TO THE GENERAL ASSEMBLY ON THE FEASIBILITY OF A LARGE USER ACCESS PROGRAM FOR LARGE ELECTRIC SERVICE CHOICE

DOCKET NO. 04-0614

INITIAL COMMENTS OF OKLAHOMA GAS AND ELECTRIC COMPANY

I. BACKGROUND

The Arkansas Public Service Commission (the "Commission") initiated this proceeding with an Order issued on April 23, 2004 in response to Section 17 of The Electric Utility Regulatory Reform Act of 2003 ("Act 204") which was enacted by the Arkansas General Assembly that required that the Commission:

... conduct a collaborative meeting to study the feasibility of a large user access program for electric service choice, including a commitment to insure there is no cost shifting to any other class of customers, and report to the General Assembly on or before September 30, 2004.

The Order made Oklahoma Gas and Electric Company (OG&E) an official party to this proceeding and requested official parties to provide written comments regarding the feasibility of a statewide large user access program for electric service choice. Specifically, the Commission requested parties to address:

1. the infrastructure necessary to put a large user access program in place,
2. the costs which would be incurred to implement the program,
3. the costs which could be stranded as a result of the program, the steps that would be necessary to insure that there would be no cost shifting to any other classes of customer,
4. the likelihood of participation by large users, and
5. evidence of the level of interest in such a program, including surveys of potential participants.

A. Changes in the Industry Environment

1. Historical Content

To put OG&E's comments in this proceeding in context, it is essential to identify the changes in the industry environment that have occurred since the Arkansas Public Service Commission originally commenced a set of rulemaking proceedings to develop the appropriate rules for implementing retail choice in Arkansas. In these rulemakings, OG&E identified the infrastructure necessary to put a retail choice program in place, the costs which would likely be incurred to implement a retail choice program, and the costs which could be stranded as a result of a retail choice program. However, in these rulemaking dockets, it was
envisioned that all customers would be allowed to choose their electric supplier, not just a handful as is being considered in this proceeding.

The biggest changes in the industry environment are: 1) the surplus generating capacity in the region, 2) the financial distress of merchant generators and IPPs, 3) the volatility in natural gas prices resulting from the large increase in natural gas-fired generation, and 4) the evolution of Regional Transmission Organizations (RTOs).

In 1998 and 1999, wholesale power prices rose to a level that had previously not been seen in the industry. During 1998, wholesale power prices on parts of the Eastern interconnected grid reached as high as $5,000/MWh. In the northern SPP market, spot market prices for power during 1999 reached as high as $2,200/MWh (Power Markets Week, Aug. 2, 1999, p. 2). During 1999, prices in other parts of the Eastern interconnected grid reached as high as $10,000/MWh. Reported spot market wholesale prices reached a high of $3,400/MWh during 2001 in the California Oregon Border and Palo Verde markets and reached a high of $5,000/MWh in the Mid-Columbia market on December 11, 2000. Beginning in 1998, there have been numerous occasions when wholesale power prices have exceeded the $100/MWh that was typically specified in the old interconnection and interchange agreements.

The response to these high wholesale prices was independent power producers and merchant generators constructing additional generating capacity to take advantage of these high wholesale power prices. Gas-fired generating units were typically the generating technology of choice for a number of reasons. First, gas-fired generation could be built much more quickly than a coal-fired generating plant. It typically takes between two and three years to plan, permit and construct a gas-fired generating unit, while it takes 5 years or more to plan, permit and construct a coal-fired generating unit. Using a gas-fired generating technology would allow the plant owner to get into the market more quickly and take advantage of the high wholesale power prices. Second, environmental permitting was much easier for a gas-fired generating plant. Third, it was usually much easier to get local communities to accept a gas-fired generating plant in their vicinity. Such local acceptance was much more difficult for a coal-fired generating unit.

Much of this new gas-fired capacity was constructed by unregulated merchant generators outside of the integrated planning process that is typically used by utilities. Historically, when a vertically integrated utility added generation, it also evaluated and added the necessary transmission to allow the new generation to serve the load. This helped to assure that generation and transmission would function effectively as a unit. However, the new generation that was added by merchant generators and independent power producers was not planned and built as a part of this coordinated planning process. The new merchant power plants coming on line have constructed their facilities at locations of their
choosing, usually based on considerations such as fuel availability, access to transmission and permitting and siting ease. The merchant generators and independent power producers did not share their plans to construct new gas-fired generation with utilities or regulators other than what they needed to share to get interconnected to the grid, to get transmission access and to get the necessary permits.

2. **The Industry Environment Today**

When a number of merchant generators and independent power producers all tried to take advantage of the high wholesale power prices at the same time, the result was significant excess capacity in many wholesale power markets in the United States. This occurred because the planning for these generating units was not coordinated with load serving entities or with other companies planning to add generation. Each entity did an independent analysis and believed that it would capture the high wholesale prices if it could only get to market quickly. Unfortunately, an unrealized assumption in these analyses was that no other parties would act to take advantage of the business opportunity that high wholesale prices represented. It is a paradox of the markets that whenever a large number of participants all try to take advantage of the same business opportunity, the opportunity typically does not materialize. This excess capacity that has resulted from this uncoordinated over-expansion has led to low wholesale power prices in many markets which has resulted in significant financial distress for merchant generators and independent power producers. This problem has been recognized in the industry press as illustrated by the following quote from a recent article.

Excess capacity remains because the industry built more than it could possibly use, retirements of older coal and nuclear plants did not occur as expected, and the economy appears to need much less electricity than foreseen by developers and lenders, due in part to a shrinking manufacturing sector. (Power Markets Week, February 9, 2004, p. 14)

The magnitude of this problem has been recognized by analysts covering this industry.

In a recent report, ABN AMRO estimated that there is roughly 56,000 MW of generating capacity currently for sale in the U.S. Some 33,000 MW of that is classified as "distressed merchant", while the remaining is qualifying facility power or "other facilities" that benefit from power purchase agreements. (Power Markets Week, February 16, 2004, p. 15)

The financial impacts of this excess capacity have also been recognized by analysts.

Fitch Ratings analysts do not see the wholesale power markets
recovering soon, even though the agency believes power prices have bottomed out this year. ... The higher prices in Fitch's "base case" still will not be high enough to cover fixed costs and debt service. "The good news is prices are projected to rise from 2004 onwards. The bad news is, the level of net revenue [after fuel and variable operation and maintenance costs, but before fixed costs, debt service, and return on capital] is still too low to cover fixed costs and debt service," especially in the PJM West and Midwest regions. (Power Markets Week, November 3, 2003, p. 8)

Another industry analyst noted that:

In an October 2003 report, "Refinancing Needs and Poor Credit Quality Still Challenge U.S. Merchant Sector," S&P Director Arleen Spangler stated that S&P did not see much improvement for the sector due to significant leverage, surplus capacity, illiquid markets, and uncertain cash flows. "The strategy of both borrower and lender appears to be to ride out this difficult period and wait for energy markets to improve. If this does not occur by the time many of the refinanced loans come up for renewal, there may be more failures." (Power Markets Week, February 9, 2004, p. 14)

Reporting on the recent Cambridge Energy Research Associates' Annual Executive Conference, an industry publication noted that:

The "merchant generating model" in the U.S. has been so ravaged financially that it may not be salvageable, according to a number of industry executives who spoke at CERA. Federal regulators, they argued, may have to consider ending their support of the concept and allow utilities to purchase more of the distressed generating capacity. Cinergy President and CEO James Rogers said some state regulators, looking to increase reserve generating capacity, are asking regulated utilities to look at buying existing units as a lower-cost alternative to building Plants. (Power Markets Week, February 16, 2004, p. 1)

3. **Risk in the Wholesale Market**

These recent events and changes in the wholesale market have significantly increased the risk of purchased power. Factors that have increased the risk associated with power purchases include:

- Counterparty risk
- Risk of encountering transmission constraints
- Uncertainty of the financial impacts on customers resulting from actions of the Federal Energy Regulatory Commission
- The volatility inherent in market-based pricing
- Concerns about deliverability and economic interruptions
a. Counterparty Risk

Counterparty risk is defined as the possibility that the other party in an agreement will default. In a purchased power contract, the risk of the seller not delivering the power as agreed to the utility would be counterparty risk. This could result from the counterparty being financially insolvent or from being physically unable to deliver on the contract. In the current industry environment, insolvency is a real concern. An article in a recent industry publication stated that:

More U.S. energy merchant companies are likely to file for bankruptcy in the next few years as "almost every worst case scenario that these companies and their lenders considered possible, but remote, has become its base case scenario," Standard & Poor's said Feb. 2 in a new report that was more pessimistic than those previously published. With market conditions condemning them to low - if any profits - and continued high risk, "energy merchants must find a way to reduce their crushing debt burdens and do so fairly quickly if they are to survive." (Power Markets Week, February 9, 2004, p. 13)

An example of this counterparty risk and/or reliability risk is Potomac Electric Power's purchase power agreements with Mirant.

Mirant and Potomac Electric Power last week ended a months-long feud by renegotiating two power contracts that the bankrupt power marketer had sought to abrogate after filing for Chapter 11 this summer. Under the new deals, Pepco said its cost would rise by about $60 million, a number sharply less than the $150 million increase it could have incurred had Mirant canceled the pacts, forcing the utility to shop for power in the open market. (Power Markets Week, November 3, 2003, p. 9)

The same article noted the no-win situation that results from attempting to restructure purchase power agreements in bankruptcy proceedings:

the recent disputes among generators, buyers, bankruptcy court, and the Federal Energy Regulatory Commission are unfavorable either way. If FERC prevails and forces a bankrupt generator to continue to perform under a money-losing contract, as it did with NRG Energy and Connecticut Light & Power, the costs recovered may not cover debt service, hurting investors, and boosting generators' cost of capital, she explained. But lower cost recovery will hurt investors in the merchant's fixed income debt.

However, if a bankruptcy court lets a generator terminate a
contract, as Mirant was able to achieve regarding its contract with Potomac Electric Power, utilities and regulators will see such contracts as presenting a greater risk to customers. So both alternatives favor utilities building their own plants, Lapson continued. "It's a no-win situation for robust wholesale market competition," she declared. (Power Markets Week, November 3, 2003, p. 8)

With the failure of ENRON, which at the time was the largest power marketer in the nation, the concerns about counterparty risk have escalated. The trade press is full of announcements of power marketers that are significantly scaling back or leaving the business. In an article regarding Duke Energy North America ("DENA") exiting speculative trading of electricity, gas and crude oil, it was noted that:

The DENA withdrawal means nine of the top ten players in the trading market for the third quarter of last year have now either totally withdrawn or pulled back substantially from the power trading market. (Power Markets Week, April 14, 2003, p. 26)

A purchased power contract does not mean much if the counterparty exits the business. There is also a concern when a counterparty sells its book of contracts to another party. The buyer did not choose to enter into an agreement with the new purchaser of the trading book, and this new counterparty may not be acceptable to the buyer for a number of reasons.

b. Transmission Related Risk

Historically, when a vertically integrated utility added generation, it also evaluated and added the necessary transmission to allow the new generation to serve the load. When power is purchased from a power marketer, it is typically blended from resources that the power marketer has access to over a large geographic area. Delivery of this purchased power can be interrupted if transmission constraints are encountered along the path used to move the power to the customer from the resources owned or controlled by the power marketer. Similar transmission constraints may even exist within a utility's own control area when a merchant generator is sited without regard to available transmission capacity within the system. The potential for encountering transmission constraints on purchased power increase the risk of this option.

Uncertainty of the financial impacts on customers resulting from actions of the Federal Energy Regulatory Commission has also increased the risk of meeting customer needs using purchased power. FERC has abandoned its Standard Market Design ("SMD") NOPR, and there is no certainty that
an Order will ever be issued in this docket. Instead, FERC has issued a whitepaper titled "Wholesale Power Market Platform" that has backed away from significant features of SMD and provides more flexibility to adopt regional solutions. FERC has not provided a date for implementation of the wholesale market platform that it proposed in the whitepaper. The result of all this turmoil with respect to SMD is that it is unclear what the rules will be in any geographic area with respect to the price, terms and conditions of transmission service. This adds to the risk and uncertainty regarding the financial impact on customers of power purchases.

c. **Regulatory Risk**

RTOs are in the process of forming and it is unclear what the effects will be on the transmission component of unbundled electric sales to customers. Most RTOs have grandfathered transmission arrangements for bundled native load customers resulting in minimal changes in transmission costs for these customers. However, industrial customers exercising choice have not typically been allowed to continue to receive grandfathered transmission service. Customers exercising choice have been required to take transmission service under the RTO's FERC approved transmission tariff, which may include energy markets and congestion charges. It is not clear whether a customer that has exercised choice can return and be included in a utility's grandfathered bundled service. Will locational marginal pricing (LMP) eventually be implemented, which could add significant congestion costs to any purchased power that would ultimately be borne by customers? Once a grandfathered right has been given up, can it be reclaimed? Until regulators provide answers to these and other important questions, it is difficult to anticipate the financial impact of taking transmission service subject to terms and conditions that could change markedly in the future. This uncertainty can be mitigated by purchasing power on a short-term basis and taking short-term transmission service. However, short-term purchased power and transmission service could expose customers to considerable short-term price variation and long-term resource uncertainty.

d. **Price Volatility Risk**

Furthermore, increased wholesale price volatility, combined with the counterparty risk discussed above, have made it hard to find a power marketer that is willing to offer a fixed price contract longer than about 5 years. Power marketers are willing to offer long-term contracts if they contain a fixed capacity price and a variable fuel component indexed to some existing market price. This passes the risk that the marketer may have to pay more for the power necessary to fulfill the contract along to the customer. This is illustrated in a recent article that states:
Nearly all of the PPA responses involved proposals that included a capacity payment plus an operations and maintenance payment with escalators, plus a defined per-unit startup cost, plus a cost-plus fuel pricing mechanism if APS does not provide the fuel, Pinnacle West said. None of the PPA proposals involve a fixed-price bid. (Power Markets Week, Feb. 2, 2004, p. 7)

Furthermore, at the end of a purchased power agreement, there is no guarantee regarding the price to obtain the power necessary to replace this PPA. By contrast, a utility owned generating facility will continue to depreciate and the fixed cost of the power coming from this facility is likely to decline. This results in greater long-term price certainty from utility owned facilities than from purchased power agreements.

II. POTENTIAL IMPACTS OF CHANGES IN THE INDUSTRY ENVIRONMENT

How do the changes in the industry environment described above impact providing a large user access program for electric service choice? Because of the significant excess capacity and large reserve margins that exist in the Midwest, the wholesale market price of electric power is likely to be low initially and for several years into the future, which may entice a number of large users to switch to alternative suppliers. The low level of wholesale prices that could provide an incentive to switch would also result in higher calculated stranded generating costs for regulated utilities.

If customers experience problems with alternative suppliers, such as counterparty risk, problems with deliverability due to transmission constraints and economic interruptions, and unexpected congestion costs, these customers may want to return to standard, tariffed utility service. Shrinking reserve margins and increased wholesale price volatility could also result in these customers who have selected alternative suppliers wanting to return to standard, tariffed utility service. Many of the risks associated with purchasing power from an alternative supplier can be avoided by a customer purchasing power from a vertically integrated utility in whose control area it is located. Because of the financial stability of most regulated utilities, there is little or no counterparty risk. By purchasing from the local vertically integrated utility that typically owns generation within its control area, the risk of potential transmission curtailments interfering with a customer’s service would also be minimized. A change in the provisions of FERC’s wholesale market platform could affect the financial impact of purchased power on a utility’s customers but is less likely to affect the price or delivery of power from resources that a utility owns within its service territory and which are subject to state regulatory jurisdiction.

Large customers leaving the regulated utility supplier for their energy needs will result in several shifts in costs, and these cost shifts will affect all of the utility’s customers. Permitting large customers to return to the utility if they experience problems in retail choice could result in additional cost shifts among all of the utility’s customers. In the following discussion OG&E identifies some of the cost shifting that is likely to occur
resulting in higher costs being imposed on the utility's captive customers. It is essential for the Commission to have clear and well established return to system rules in order to protect remaining customers from these potentially higher costs.

III. COST SHIFTING

There are several forms of cost shifting that the Commission needs to guard against. The first is cost shifting among jurisdictions. At the present time, retail choice has been put on hold in Oklahoma and it is not clear that retail choice will be implemented in Oklahoma, either for large users or for other retail customers. The changes in OG&E's infrastructure and practices necessary to implement retail choice should be clearly assigned to the jurisdiction that required these changes. If Oklahoma does not implement retail choice, the costs that OG&E incurs in implementing retail choice should be assigned to OG&E's customers in Arkansas and OG&E's Oklahoma customers should be insulated from such costs. This would require a jurisdictional split of OG&E's assets, revenues and expenses and would require OG&E to segregate its revenues and expenses between Arkansas and Oklahoma. This could entail jurisdictional splits of things like off-system sales revenues, fuel and purchased power adjustment clauses and assigning generating units to specific jurisdictions in order to accurately accomplish this jurisdictional split.

The second form of cost shifting that the Commission needs to guard against is cost shifting among classes of customers within a particular jurisdiction. It would be necessary to ensure that costs incurred to implement retail choice for customers who choose an alternative supplier are not passed on to the remaining customers who do not opt for retail choice. Regulated utilities have incurred costs to serve all customers pursuant to their service obligation. The contribution made by industrial customers to the utility's revenue requirement will be lost when industrial customers are permitted to leave the utility, and that loss of revenue will result in stranded costs unless measures are taken to permit the utility to continue to earn a fair, just and reasonable return on its investment. Remaining customers receive no benefits from the retail choice program and it would be unfair for them to have to pay for the cost of implementing a retail choice program. The Commission would need to create mechanisms to ensure that such cost shifting does not occur, which would include clear rules regarding whether a customer could return to bundled utility service and on what terms and conditions the customer could return. Even if the Commission sets clear return to system rules, there is likely to be pressure on state government officials and on the Commission to relax these rules to preserve jobs and mitigate potential negative impacts on local communities if large users want to return to bundled utility service. The Commission would also need to be clear about the rules for assigning costs to a class of customers in a cost of service study used to determine delivery service rates for customers who opt for choice and bundled service rates for customers who do not opt for choice.

The third form of cost shifting is a subtle one which involves utility reserve margins. Large reserve margins put downward pressure on wholesale price levels, tend to mitigate wholesale price volatility and also help maintain a high level of system
reliability. Large customers who opted into retail choice would benefit from the lower wholesale price levels, decreased wholesale price volatility and maintaining a high level of system reliability that would result from higher reserve requirements. Furthermore, customers who opt for retail choice would benefit significantly if the remaining customers would bear the cost of maintaining adequate reserve margins. The Commission needs to ensure that customers who opt for choice bear their fair share of the financial burden of maintaining adequate reserve margins.

IV. COST SHIFTING AND PIECEMEAL RETAIL CHOICE

OG&E believes that the large user access program for electric service choice that is being considered in this proceeding is a bad policy and should not be pursued by the Commission. It would be inefficient to have two sets of business systems and infrastructure in place, one for those that opted into choice and one for those that did not. Thus, the costs for implementing choice for a subgroup would not differ substantially from the costs of implementing choice for all customers. If the Commission implements the necessary mechanisms to prevent cost shifting, the costs of implementing a retail choice will be spread over a relatively small number of customers resulting in large per unit charges to customers that adopt choice. Being able to spread the costs of implementing retail choice over all customers would provide lower unit costs from implementing choice. However, this is not possible if piecemeal retail choice is pursued with adequate mechanisms to prevent cost shifting. Thus, the piecemeal retail choice that would result from a large user access program for electric service choice would provide the Commission with two bad alternatives.

If the Commission were to adopt adequate mechanisms to prevent cost shifting, the costs of implementing retail choice would be spread over relatively few customers with large unit charges for implementing choice as the result. With large unit charges it is doubtful whether such a program could be successful. On the other hand, if the Commission pursues low unit charges for implementing choice by spreading the costs of implementing choice over all customers, the Commission would shift costs to customers who do not opt for retail choice and violate the prohibition against cost shifting. Because either alternative is an inappropriate result, OG&E believes that piecemeal retail choice is a policy that the Commission should not pursue.

The Commission should be wary of those that might suggest offering a program and seeing what happens. Once the cost of the business systems and infrastructure changes to implement retail choice are incurred, these costs need to be recovered by the utility. This is particularly true when, as is the case here, the utility would be ordered to offer such retail choice programs. Recovery of these costs could present a problem for the Commission if relatively few customers decided to participate, or worse yet, if no customers decided to participate. If adequate mechanisms are implemented to prevent cost shifting, there would be an economic incentive to not be the first customer to participate or even one of the first few customers to participate, because the full costs of retail choice implementation would be borne by these few customers. If there is an economic incentive not to be first, it is difficult to see how such a program could get off
the ground. In OG&E’s opinion pursuing retail choice on a piecemeal basis just does not make sense.

V. IMPLEMENTING CUSTOMER CHOICE FOR LARGE USERS

If the Commission decides to pursue piecemeal retail choice, the Commission has several choices for implementing retail choice for large users. The first is to make it possible for large users to purchase from alternative suppliers but also allow large users who are not interested in retail choice to continue to take bundled utility service at the appropriate regulated rate. Put another way, OG&E would be the default provider unless the large user opted into retail choice. Both the costs of implementing choice and, more importantly, the billing determinants used to calculate rates are likely to change as new customers select retail choice. If the Commission were to pursue this first option, it would need to adopt formula rates that could change regularly as new customers opted into retail choice. The Commission would also likely need to change the way that off-system sales revenues are credited to customers to account for customers opting into retail choice. This would be necessary both to ensure that customers who opt into choice do not receive credits from generating resources that they no longer financially support and to level the playing field with alternative suppliers who do not have to pay such credits.

The second option is to require all large users to select an alternative supplier and no longer allow any large user to continue to take bundled utility service. While this second approach may seem rather extreme at first, it may make it much easier for both the utility and the Commission to implement a retail choice program for large customers. Allowing customers to adopt retail choice whenever they want makes it difficult to determine stranded costs and would require a re-determination of stranded costs and a re-allocation of the costs of implementing retail choice as new customers opted for choice. It would also be more difficult for the utility to do resource planning if large users could purchase from alternative suppliers whenever they wanted. Resource planning would be much easier if the utility knew that it would no longer have to plan and obtain generating and purchased power resources for large users. Additionally, the costs of implementing retail choice would be spread over the largest pool of possible beneficiaries, thus reducing the unit costs for implementing retail choice for large customers. It would also address the economic incentive not to be the first to participate that was discussed above. Furthermore, the costs of implementing choice would not need to be continually re-calculated as additional customer left the system.

Another question that must be answered is whether OG&E would be required to take a customer back as a bundled service customer if the large user exercised its option to enter retail choice. For the reasons discussed above, a customer who exercised choice could decide to return to the regulated utility supplier if the wholesale market supplier does not provide reliable power or if the customer could achieve better economic results from bundled service than service from another electric supplier. However, the very conditions that make it advantageous for customer to return to bundled service would likely increase the costs to OG&E’s remaining customers if this return to bundled
service is permitted. To avoid imposing subsidies on other customers, OG&E believes that if a customer that has chosen to obtain electric service from the competitive market is allowed to return to the regulated utility, the returning customer should be permitted to return only if the returning customer’s electric rates are set to recover the incremental cost of providing electric service to that customer. OG&E believes that a returning customer should always be an incremental cost customer once it had exercised retail choice.

VI. NECESSARY INFRASTRUCTURE AND COSTS FOR IMPLEMENTING A CHOICE PROGRAM FOR LARGE USERS

A description of the changes in business systems and infrastructure that OG&E believed would be necessary to implement retail choice is provided in the attached internal presentation dated March 8, 2001. These were the changes that OG&E believed were necessary to implement retail choice in Arkansas as it was originally proposed. There would likely need to be modifications to these identified changes to accommodate OG&E’s integration into the SPP RTO and to accommodate retail choice offered on a piecemeal basis. However, OG&E believes there are a number of good reasons not to pursue piecemeal retail choice that OG&E has identified above. The time and effort needed to identify the changes to the business systems and infrastructure necessary to offer piecemeal retail choice and to provide cost estimates of these changes to its business systems and infrastructure is neither necessary nor productive given the inherent flaws in offering piecemeal retail choice. If the Commission indicates a desire to pursue piecemeal retail choice, OG&E will devote the time and effort to identify the necessary modifications and the associated costs. However, OG&E believes that the attached presentation provides sufficient insight to the scope of the necessary modifications to business systems and infrastructure to provide the Commission with a basis for reaching a decision in this proceeding.

VII. RESULTS OF THE CUSTOMER SURVEY RESULTS

OG&E had an independent research firm conduct a survey of its large customers in Arkansas to assess the likelihood of them participating in a large user access program and to assess their level of interest in such a program. A copy of the survey results is attached to these comments. There are several points that need to be highlighted in these survey results.

- The majority of the large customers had not heard of the Electric Utility Regulatory Reform Act of 2003.
- When customers were asked about the feasibility of a large user access program, the majority believed that it was feasible.
- Customers were split on whether there would be cost shifting or whether the rates for the other customer classes would increase as a result of a large user access program.
- All of the large customers wanted the flexibility to switch back and forth between non-regulated power markets and the regulated utility system.
This last result is worrisome. A program with the flexibility to switch back and forth between non-regulated power markets and the regulated utility system would make it very difficult to plan the regulated utility system and to protect other customers from cost shifting.

**VIII. SUMMARY**

OG&E believes that the large user access program for electric service choice that is being considered in this proceeding is a bad policy and should not be pursued by the Commission. The prohibition against cost shifting to non-participants would result in large unit costs for implementing choice, because the costs of implementing retail choice would be spread over a relatively small number of participating customers. This would create an economic incentive not to participate in such programs and make offering such a program self defeating. Furthermore, the results of OG&E's survey indicate that the kind of program in which most customers are interested would allow them to switch back and forth between non-regulated power markets and the regulated utility system. Such a program would make it difficult to protect OG&E's other customers from cost shifting. With the poor economic incentives to participate in large user access programs and the kind of flexibility that large customers are seeking, OG&E concludes that a large user access program that provides retail choice on a piecemeal basis should not be pursued by the Commission.

Respectfully submitted,

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Attorneys for Oklahoma Gas & Electric Company

[Signature]

Lawrence E. Chisenhall, Jr., #74023
Utility Business Transformation Project

Deregulation Business Requirements

Results

March 8, 2001
Meeting Objectives

• Communicate deregulation business requirements
  – Many accomplishments in a short period of time
  – Update the Utility Operating Council (complete the snake)

• Opportunity to work smart
  – More planning and more planning
  – “Hotel” our way to a flexible implementation strategy
  – Engage your support to keep members and supervisors focused on long-term objectives

• Communicate what’s next for deregulation transition
  – Deregulation Business Requirements Orientation classes
  – Communicate when policy decisions are needed
  – Integrate business requirements into comprehensive blueprinting and implementation plan
Deregulation teams defined 487 business requirements, developed 77 process flows, 4 timelines, 2 system diagrams and one market model

• OG&E subject matter experts represented the following key business areas:
  - Billing
  - Front Office
  - Back Office
  - Settlements and Profiling
  - CSP Service
  - Electronic Data Exchange (EDE)
  - Business Separation
  - Power Delivery

• Billing: Rodney Buchanan, Tim Lyon, Steve Santelmann, John Parham, Jeff Boren, James Chappel, Bill Dennis, Mike Young, Roger Walkingstick, Steve Goodner

• Front Office: Randy Jones, Kenny Kerr, Cheri Davidson, Lisa Cochran, Tim Lyon, Paul Riess, Marvin VanBebber, Carol Shoemake

• Back Office: Floyd Hunsaker, Joe McGowen, Rodney Buchanan, Tim Lyon, Ken Campbell, Rick Green

• Settlements and Profiling: John Gunesch, Clay Scott, Phil Bartholomew, Don Hargrove, Steve Holloway, Buz Poole, Bill Wylie, Les Brown, Everett Ernst, Mel Perkins

• CSP Service: Kim Morphis, Joe Menefee, Mel Perkins, Everett Ernst, Rick Reich, Les Brown, Tim Lyon, Bill Bullard

• Electronic Data Exchange (EDE): Tim Lyon, Cheri Davidson, Floyd Hunsaker, Clay Scott, Rodney Buchanan, Kerri Young, Mike Lyons, Jack Stefanick, Dave Webb


• Power Delivery: Kenneth Williams, Larry Potter, Gary Gardner, Pat Saxton, Phil Apple, Billy Keith, Kenny Kerr, Lisa Cochran, Randy Jones
Work Scope: Determination of Customer Choice Business Requirements

Working Session Deliverables
- Working assumptions
- Business requirements
- Work process flows
- Policy issues
- Parking lot items
- Completed work assignments
- Reference documents
- Discussion notes

See Appendix for detailed description of working sessions
Key assumptions provided a framework for the working sessions and the development of Business Requirements

Below is a sample list of some of the key assumptions:

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<th>Major Assumptions</th>
<th>Outstanding Issues</th>
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<td>Back Office</td>
<td>• Payment Hierarchy: EU will get paid first</td>
<td>• Business Policy: purchasing of REES/ESP receivables: &quot;Made Whole Scenarios&quot;</td>
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<td></td>
<td>• Service disconnection activities: only for EU company charges</td>
<td>• Risk management policies: e.g., payments collected by the REES/ESP on behalf of the EU when REES/ESP goes out of business</td>
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<td></td>
<td>• Credit Policies: separate for EU and REES/ESP</td>
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<td>Billing, including Meter and Metered Data</td>
<td>• The EU will be the Continuity of Service Provider: no &quot;external&quot; communication of meter readings, billing amounts, etc. will be required for CSP customers</td>
<td>• Business Policy: AMB, collective billing, non-metered accounts, RTP program and new proposed tariffs (switching, etc.)</td>
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<td>• OG&amp;E will support Consolidated Billing (EU), Consolidated REES/ESP (ESP), and Dual/Multiple Billing</td>
<td>• Business Policy: what billing methods will OG&amp;E support: Bill Ready, Rate Ready, and OG&amp;E REES/ESP – all of the above?</td>
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<tr>
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<td>• Target threshold for interval meters in the OG&amp;E service area is all customers &gt;200kW (additional 8,000 meters)</td>
<td>• System risk analysis: determine billing requirements for number of customers served by CSP; consolidated billing</td>
</tr>
<tr>
<td></td>
<td>• All OG&amp;E generation plants will require billing accurate meters</td>
<td>• Business Policy: handling of billing inserts for non-OG&amp;E parties</td>
</tr>
</tbody>
</table>

Utility Operating Council -- March 8, 2001
Key assumptions provided a framework for the working sessions and the development of Business Requirements, cont’d.

- Below is a sample list of some of the key assumptions:

<table>
<thead>
<tr>
<th>Topic Area</th>
<th>Major Assumptions</th>
<th>Outstanding Issues</th>
</tr>
</thead>
</table>
| CSP              | • A new functional group will be needed to complete the duties of the Continuity of Service Provider: schedule (and forecast); administer Standard Service (SSP) tariffs; acquire power (RFP, contracting, contract administration, and transmission); reconcile RTO settlement statements; and track customers, energy costs and customer move costs  
  • CSP will require a separate company code in SAP  
  • OG&E may utilize its retail/wholesale affiliates during the rate freeze period | • Business Policy: risk management and credit issues around the CSP  
  • Business Policy: handling of Cogeneration contracts  
  • Business Policy: fees/frequency for customer switching |
| Load Profiling   | • OG&E will provide a “one time” data dump of aggregated customer information for all certified REES/ESP’s  
  • The Commission will require “Rate Class” samples vs. “Rate Code” samples  
  • For every Municipal who opts in, the Municipal will be the CSP | • Business Policy: should the Load Profiling group be a shared entity of OGE Energy Resources and OG&E Electric Services  
  • If OGE has the contract for wholesale energy today, the CSP may be required to fulfill obligations for that Muni  
  • Business Policy: should OGE pursue opportunities to provide services to Municipals and Co-ops? |
Key assumptions provided a framework for the working sessions and the development of Business Requirements, cont’d.

Below is a sample list of some of the key assumptions:

<table>
<thead>
<tr>
<th>Topic Area</th>
<th>Major Assumptions</th>
<th>Outstanding Issues</th>
</tr>
</thead>
<tbody>
<tr>
<td>Front Office</td>
<td>• Customers can switch as frequently as every meter reading</td>
<td>• Business Policy: functional location and timing of REES/ESP Business Center</td>
</tr>
<tr>
<td></td>
<td>• OG&amp;E will need to establish a REES Business relations group</td>
<td>• Business Policy: handling of marketing program inquiries (heat pump loans, Watts Dogs, etc.)</td>
</tr>
<tr>
<td>EDE</td>
<td>• Within the first year of Retail Open Access, 15% of customers will enroll with a REES/ESP</td>
<td>• Business Policy: define policy/rule for data exchange with REES/ESP for Load Profiling and Settlement</td>
</tr>
<tr>
<td></td>
<td>• Interval data will be interrogated on the data warehouse by the REES/ESP, therefore, there will be no impact on transactions from interval data</td>
<td>• Business Policy: pre-enrollment process in which customers designate their information can be placed in a database for registered REES/ESP to access</td>
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<tr>
<td>Business Separation</td>
<td>• Systems shared between the business units must be logically separate and secure, but need not be physically separate</td>
<td>• Business Policy: should the EU be providing services for a competitive affiliate?</td>
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<tr>
<td></td>
<td>• Business Separation will not occur until 1/1/03</td>
<td>• Legal: do shared services have to be located in the Shared Services entity, or can they be located anywhere in the corporation?</td>
</tr>
</tbody>
</table>

Utility Operating Council -- March 8, 2001
To comply with Deregulation Requirements, the following new processes were defined

- **REES/ESP Registration** – to activate OG&E’s relationship with the REES/ESP
- **REES/ESP Registration Renewal** – to renew OG&E’s relationship with the REES/ESP on an annual basis
- **REES/ESP Deregistration** – to end OG&E’s relationship with a REES/ESP due to contractual default or APSC/OCC decertification
- **Customer Pre-Enrollment** – to allow customers the ability to make their load information to REES prior to Retail Access
- **Customer Enrollment** – to handle customer switching activities related to Retail Access, including enrollments, drops and returning to OG&E CSP Service
- **REES/ESP Account Management** – to manage relationships with REES/ESP’s
- **Data Exchange** – to send and receive data between REES/ESP’s and OG&E
- **Creation of Aggregated Load Profiles** – to produce daily aggregated load profile data for use in settlement calculations by RTO
- **CSP Reconciliation and Dispute Resolution** – to reconcile settlement statement from the RTO that calculates transmission services, ancillary services and other charges associated with energy delivery for OG&E’s CSP Standard Service Package
The working sessions also identified existing processes requiring major modifications

- **Retail Billing** – to handle new unbundled bill formats, bill calculations and invoicing (3 billing scenarios where REES/ESP bills all; OG&E bills all or each bills a separate bill)

- **Retail Payment, Remittance, Collections** – including new collection notices and payment hierarchy

- **Customer Inquiry Handling** – to handle inquiries for direct access related requests (over 30 process changes, e.g., high bills)

- **Credit and Collections** – to monitor REES/ESP credit worthiness and secure appropriate collateral; perform liquidation and write off

- **Interval Meter Installation and Exchange, Meter Reading, Data Storage, Data Access, and Transfer** – modifications to current processes for customers now associated with Retail Access

- **New and Existing service install** – examination of process for compliance to non-discriminatory practices and benchmarks
The recommendation is for OG&E to establish three new Business Organizations

• A REES/ESP Business Center would serve as the primary point of contact between OG&E and the REES/ESP for one or more of the following business transactions:
  – Registration, De-registration, Registration Renewal;
  – Customer Enrollment;
  – Data Exchange;
  – REES/ESP Relations;
  – Business-to-Business Billing;
  – Dispute Resolution; and
  – Secondary responsibility for contract/tariff, APSC/OCC and other communications, outage management, customer history requests, customer calls, and IT technical support

• A separate CSP organization would serve the customers who choose not to switch to an ESP and would administer the Standard Service Package (SSP)

• An affiliate compliance team will need to monitor and administer compliance with Affiliate Rules (function could be contained within an existing department)
Credit and Collection Requirements

1. Automate transactions (EDI):
   - Communicate all final reads to the REES/ESP
   - Notify REES/ESP of scheduled non-pay disconnects for C&I customers
   - Send notification to REES/ESP when OG&E reconnects their customer
   - Track the mailing date and hence the due date of the REES/ESP Consolidated Bills

2. Implement payment hierarchy to differentiate REES/ESP line items from OG&E line items
   - Place REES/ESP dunning messages on OG&E consolidated bills
   - Develop process for incoming ACH files (EDI 820 format)
   - Receive and post aggregated and individual payments
   - Generate reports for corrected payments received
   - Generate a report of payment line items that cannot be posted

3. Calculate individual deposit amounts on CSP service, Distribution, Customer Service and Competitive Services

4. Develop a new process of communicating with the collection agencies on which parts of the bill (G, T, D, CS, CS) OG&E is sending for collection

5. Train and educate the bill pay assistance agencies on unbundling of the bill

6. New process to record and report customer allegations of slamming by REES/ESP
Profiling

7 of 85 Requirements

1. At market opening, aggregated historical profiles need to be posted on the Internet
2. Calculate and post distribution loss factors electronically
3. Install profiling system that creates and stores 3 types of profiles daily
   - Forecast
   - 3-days after
   - Final
4. Calculate and implement annual scaling factors for creation of customer segmented profiles
5. Integrate load profiling systems with MV-90, SAP, LodeStar and enrollment systems
6. Automate profiling system process to accommodate volume increases in daily profiles and daily profile calculations
7. Implement data storage and data management (data warehouse) for audit purposes
Load Profiling & Settlement Proposed Implementation

Timelines (to be further developed and validated)

- Business Requirements Complete
  - All Samples in Place
- Technical Design & Gap Analysis Complete
  - Final Contract Signed & Statement of Work
- Integration Testing
- Live System Calibration & Additional Testing
- Begin Market (System) Test
- Market Opens

- Internal Process Test
- Staff Training Completed (90% Proficiency)

- Training Begins on Live System
- 13 months or Rate Category Analysis Completed
1. Install a reconciliation system
   - Store EDE transactions from SPP
   - Reconcile all calculations performed by RTO that are found on CSP settlement statements and invoices

2. Daily interrogation of meters for settlements and reconciliation purposes
   - End use customer meters
   - Interconnections with other utilities
   - Non-OG&E distribution companies
   - Generators

3. Conduct interim settlement using profiled and estimated meter data
   - Daily tracking and posting of payments and receivables
   - Calculate and apply losses

4. Conduct final settlement using actual interval and profiled meter data

5. Perform settlement – hourly intervals
   - Initial settlement is performed 3 days after event day
   - Final settlement is performed on the 1st business day following the 44th day after the event day

6. Send VEE adjusted meter data (loss adjusted) information daily aggregated by REES/ESP to RTO
Continuity Service Provider

8 of 31 Requirements

1. Provide billing and collections for customers receiving SSP
2. Create and track the following forecasts: month ahead, week ahead, day ahead and hour ahead
3. Create a balanced schedule of hourly intervals to be submitted electronically to the RTO and schedules must be stored and tracked
4. Reconcile settlement calculations performed by RTO
5. Process and track invoices from the RTO on a weekly basis and settlement statements on a daily basis
6. Post invoices and set up accounting for RTO receivables and payables in the SAP accounting system
7. Administer risk management policy around imbalance charges and costs of inputs
8. Automate reconciliation, scheduling, forecasting, workflow tracking, contract management and dispute resolution and management
9. Set up SAP system for payments to SPP (RTO) and remittances from SPP (RTO)
10. Track payments made to RTO and payments expected from the RTO

Utility Operating Council -- March 8, 2001
CSP Proposed Implementation Timelines
(to be further developed and validated)

Staffing of CSP Organization Completed

- Business Requirements Complete
- Tech. Spec & Design Gap Analysis
- System & Integration Build
- Integration Testing
- First Unbundled Bill
- Scheduling, Forecasting, Reconciliation etc. Systems in Production
- Market Opens (End Market Test)

Utility Operating Council -- March 8, 2001
Transmission and Distribution Outage Requirements

1. Transmission owner responsible for filing revenue requirements with FERC
2. OG&E needs to make modifications to the energy imbalance tariffs once retail open access rules and SPP market settlement rules are finalized
3. Transmission owner will use the license plate model for transmission tariffs and evaluate this model after 5 years
4. Implement LMP (local marginal price) used for congestion management
5. Develop tariffs/charge customers for network services
6. Develop transition plan for grand fathered transmission contracts (plan is not renewed – by 2008, all moves to Pool tariff)
7. Develop process to send after-the-fact outage notifications to the REES/ESP, the EU load profiling function, and the regulators
8. Review current service restoration policy as it relates to customers associated with REES/ESPs
9. Outage notifications will need to be distributed in an automated fashion
REES/ESP Business Center

1. Establish a separate business function center to handle all REES/ESP relationship issues
   - Coordinating business-to-business billing and payment
   - Coordinating dispute resolution with REES/ESP
   - Coordinating data exchange
   - Monitoring and maintaining REES/ESP relationships
   - Coordinating registration, registration renewal, and de-registration process
   - Participating with industry standards groups

2. Implement system to handle the volume of received REES/ESP applications, EDI transactions, and general inquiries and store for audit purposes

3. Develop a standard application form and scoring process to determine credit worthiness

4. Retrieve data from external and internal sources to complete the initial credit evaluation

5. Establish a procedure to write-off uncollectible debt due to REES/ESP non-payment

6. Develop process to determine collateral levels to cover number of enrollments

7. Develop process for Customer Care to freeze and re-enable enrollments when necessary

8. Track, timestamp, and store all contacts, steps taken, and documentation around credit issues for audit purposes
REES/ESP Business Center Proposed Implementation

Timelines (to be further developed and validated)

- Customer Enrollment Starts
- Tariffs Approved
- REES/ESP Dry Run (Operational) (3 months)

Begin OG&E Training Strategy Planning (16 months)

General AR Rules Approved (10 months)

EDI Testing (8 months)

Field Awareness Training Begins (literature) (6 months)

Assessments (systems, people)

7/03 - 11/03

Peak Front Office Season

- REES/ESP Business Center Established
- (Business & IT Leads Assigned)
- Begin handbook work (14 months)

EDIDecisions Final REES/ESP Seminar #1 (Overview)
REES/ESP Relationship Management System
Prepare consumer education materials (9 months)

AR Market Opens

Schedule release of consumer education materials (bill insert, website, media advertising) (4 months)

- REES/ESP Handbook Published
- REES/ESP Seminar #2 (More Detail) (7 months)

EDI Systems in Production (5 months)
Retail Billing

7 of 115 Requirements

1. Automated process to clear REES/ESP open line items
2. Time stamp EDI transactions associated with billing and invoicing
3. Block REES/ESP billing documents from the invoicing process
4. Combine print stream with the REES/ESP print stream into a single bill
5. Suppress tax calculations on REES/ESP “Bill Ready” data during the invoicing
6. Develop handbook and/or Standard Service Agreement requirements
7. Develop new process to interact with REES/ESP for various billing issues
1. Printed unbundled bill (five functional groups: \(G, T, D\), Customer Service, and Competitive Services)
2. Implement new SAP rates for the calculations, tracking and storage of unbundled line items
3. Send “bill ready” data to REES/ESP for inclusion on REES/ESP printed bill
4. Modify print applications in SAP to accommodate the different billing scenarios
5. Process Commission mandated inserts in REES/ESP Consolidated Billing Scenario
6. Accommodate additional printed line items associated with REES/ESP
7. Store REES/ESP information used for meter reading, billing, settlement and printing
8. Configure Stream Serve to support multi-page bills
9. Implement CCS processes based on EDI transactions
10. Maintain audit trails for transactions and acknowledgements related to EDI
11. Reconfigure mailing inserter to accommodate bills over 1 oz.
12. Analyze/select equipment necessary to support EDI transactions
Metering and Metered Data Requirements

1. Notification of third parties and customers concerning meter install process
2. Audit capabilities for tracking installation data and changes
3. Integrate meter installation workflow with CCS Front Office screen
4. Tracking workflow of different meter installation services performed for REES/ESP
5. Install billing accurate meter at each OGE generation plant
6. Add approximately 8,000 interval meters for load profile sampling and assumed target interval metering threshold
7. Add Meter Data Warehouse to store class load profiles and monthly consumption
8. Store interval probe data and make accessible to REES/ESP
9. Possible staff increase to handle additional field trips to accommodate REES/ESP requested changes, seal out of inactive meters and possible increased monthly meter reads (i.e., special reads, start and end reads)
10. Track and store consumption history for billing and settlement disputes
11. Develop tariff fee based meter data services
Front Office Requirements: Enrollment Registration/De-registration/Renewal Registration

1. Perform EDI transactions
   - Send selected customer information to the REES/ESP (ex. device location number, service level, kW history, etc.)

2. Develop process to poll customers for permission to release customer information to REES/ESP and track and store responses.

3. Track unauthorized enrollments and retain proof of all notifications

4. Implement effective enrollments on the date of the next on-cycle meter read

5. Provide individual customer information (given customer permission) via EDI, CD-ROM, and website(s)

6. Install system to track and store all REES/ESP client relationship management information collected during the registration process

7. Develop a handbook to explain rules and requirements for registration, de-registration, and renewal

8. Develop a Standard Service Agreement with language around registration, de-registration, and renewal for REES/ESP
Front Office Requirements, cont’d: Inquiries

1. Integrate SAP new set process for deregulation with CADS work order process (must be fully integrated to facilitate inquiries resolution)

2. Implement centralized tracking of customer information and issues

3. Modify all impacted inquiry processes (30) (e.g., high bill, refunds, etc.)

4. Implement screen changes to enable CSR to readily identify a customer’s REES/ESP and billing option

5. OG&E will be required to send REES/ESP notifications for new meter sets, unplanned outages, planned outages, service upgrades, energy management services inquiries

6. Develop process to check status of a REES/ESP license and certification with State during registration, de-registration, and renewal processes


Business Separation

1. Form a compliance monitoring team to track reported Affiliate Rules violations and monitor ongoing compliance

2. Implement data security measures – affiliates cannot have access to GEMS, OMS, CADs, or load profiling systems

3. Train all employees about issues relative to preferential treatment for competitive affiliates

4. Develop process for doing semi-annual reporting to regulators of violations relative to allegations of preferential treatment

5. Develop policy for employee transfers to/from competitive affiliates and file the report annually

6. Develop confidentiality statement for all employees who transfer to/from competitive affiliates

7. Develop policies for: employee transfers; preferential treatment; reporting violations; truth-in advertising; brand use; functional separation of assets, contracts and services; and confidentiality of information

8. Corporate Accounting will need to create and maintain detailed accounting records relative to compliance with affiliate rules
BSP Proposed Implementation Timelines
(to be further developed and validated)

Compliance Team Ready to Assist Other Departments with Implementation

Rewrite Contracts

Refinancing of Debt Starts

System Testing

In

Utility Operating Council -- March 8, 2001

Business Separation Requirements Finalized

Accounting Allocations (3 months)

Code of Conduct Employee Training

System Testing & Training

Market Opens - Arkansas

04/01

Staffing Process for Compliance Team

Allocation Training

Rewrite Business Separation Plan to Arkansas Commission

Budget Planning Begins

System Modifications & Reconfigurations

System Finishing

First Unbundled Bill

First Enrollments

Market Opens - Oklahoma

System Modifications & Reconfigurations

(SAP, Web Development, Records Mgmt., IACS System (archive))

- Business Separation Complete
- Cut-over date for Employee Transfer
- Start Tracking Compliance (Systems in production)
What’s next, cont’d?

**4.6X Upgrade & Files**

- **March**: Complete upgrade blueprint
- **April**: Complete realization
- **June**: System Stabilization

**Deregulation**

- **March**: Complete deregulation business requirements
  - Integrate Deregulation Business Requirements into comprehensive implementation plan
  - Schedule various Company members gain plan robustness
What's next, cont'd.?

**4.6X Upgrade & Files**
- March: Complete upgrade blueprint
- April: Complete realization
- May: System Stabilization

**Deregulation**
- March: Complete deregulation business requirements
- April: Integrate Deregulation Business Requirements into comprehensive implementation plan
  - Schedule various Company members to gain plan robustness
- Deregulation Requirements Orientation Classes (April 16-20)
  - Build pool (40-60 members) to support UBT Project
  - Classes (FO, BO, Billing, BSP, CSP, LP/Settlement)
  - Transfer deregulation requirements knowledge

Plan/schedule "deregulation policy" decisions
What's next, cont’d?

**4.6X Upgrade & Files**
- Complete upgrade blueprint

**Deregulation**
- Complete deregulation business requirements
- March
  - Integrate Deregulation Business Requirements into comprehensive implementation plan
  - Schedule various Company members to gain plan robustness

**Deregulation Blueprinting**
- April
  - Deregulation Requirements Orientation Classes (April 16-20)
    - Build pool (40-60 members) to support UBT Project
    - Classes (FO, BO, Billing, SSP, CSP, LP/Settlement)
  - Transfer deregulation requirements knowledge

**May**
- Functional Area Process Teams:
  - 1 SAP expert
  - 1 Dereg. SME
  - 4 - 5 Productivity Specialists

**Blueprinting Task**
- Conduct solution workshops (where needed)
- Document SAP deregulation functionality
- Design specific business requirements in SAP
- Design system solutions and integration strategy
- Establish teams and methodology to implement new or modified process/tasks outside SAP
Observations

- **We have a great opportunity to work smart**
  - Build UBT muscle gradually over time through short burst of training and member involvement to minimize impact on business units (Hoteling)
  - Keep deregulation planning and implementation on the radar screen of managers, supervisors and members

- **Teams accomplished a lot in a short period of time**
  - Tremendous level of definition to formerly “fuzzy” business requirements in key areas

- **Preparation for customer choice will take 18 to 24 months and require lots of hard work**
  - Our biggest challenge is to manage people, integrate new business process transformation, while remaining steadfast toward daily operational excellence
Observations, cont’d.

• Many opportunities lie ahead
  - Leverage new and existing technology (buy, build, modify, outsource)
  - Implement improved work flow management
  - Stay ahead of regulators and competitors (leverage knowledge gained in regulatory venues through proactive collaborations)

• The jury is still out on a few things
  - The ratio between standard vs. custom programming needed to complete deregulation functionality within SAP 4.6x
  - Feasibility of our existing OG&E solutions (e.g., Lode Star, etc.)
  - The level of planning commitment required for examination of Power Supply, Energy Resources, Enogex, and OGE REES/ESP needs

The required decision quality will vary from decision to decision based on individual business requirements.
Utility Business Transformation Project

Deregulation Business Requirements

Appendix

Proposed Implementation Timelines

Deliverables
Appendix – Proposed Implementation Timelines
(to be further developed and validated)

- REES Registration, De-Registration, Registration Renewal
- Customer Enrollment
- Establish REES/ESP Business Center
- End-to-End CSP Reconciliation Process
- REES/ESP Billing & Collections

Timeline:
- 3/1/03 Manual ESP Billing Ready
- 7/1/03 OGE Enrolls Customers
- 8/1/02 Business Center Established
- 10/1/03 Market Opens
- 11/1/03 First Settlement Reconciliation Calculation by CSP
- 10/1/03 Automated ESP Billing Ready
- 11/1/03 First Settlement Statement to CSP
Appendix – Proposed Implementation Timelines
(to be further developed and validated)

<table>
<thead>
<tr>
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<tr>
<td>Complete 3/1/03</td>
<td>Complete 10/1/03</td>
<td>Complete 10/1/03</td>
<td>7/1/03 Retail Access Metering Processes Operational</td>
<td>6/1/03 Direct Access Billing Functionality Ready</td>
<td>10/01/03 First Unbundled Retail Access End-Use Customer Bill Produced</td>
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Utilitv ODeratino Council -- March 8, 2001
## Appendix – OG&E Deregulation Deliverables

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<tr>
<th>Process Area</th>
<th>Requirements</th>
<th>Other</th>
<th>New Processes</th>
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Appendix – the working sessions covered many subject areas affecting deregulation implementation in Oklahoma and Arkansas

• Billing
  – Bill Format
  – Billing System Capabilities
  – Retail Access Billing Scenarios
  – CSP Billing
  – Billing Inquiries
  – Billing Services and Fees
  – REES/ESP Handbook Guidelines for Billing

• Front Office
  – Pre-Enrollment
  – Enrollment
  – Customer Care Information Processing and Delivery Methods
  – General Inquiries about Retail Access
  – REES/ESP Account Management
  – REES/ESP Registration/De-Registration/Registration Renewal
  – REES/ESP Business Center
  – REES/ESP Credit and Collections

• Metering
  – Meter data requirements
  – Interval Meter Installation Process
  – Meter Installation Timing
Appendix – the working sessions covered many subject areas affecting deregulation implementation in Oklahoma and Arkansas, cont’d.

• Back Office
  – Retail Customer Payments & Remittance
  – Retail Customer Credit Requirements
  – Retail Customer Collection Requirements

• Settlements and Profiling
  – Profiling Process
  – Settlement/Reconciliation Process
  – Forecasting
  – Transmission Tariffs
  – Outages

• CSP Service
  – CSP Standard Service Package
  – CSP Functional Roles
  – CSP Resource Requirements
  – CSP Implementation Timeline
Appendix – the working sessions covered many subject areas affecting deregulation implementation in Oklahoma and Arkansas, cont’d.

• **Electronic Data Exchange (EDE)**
  - Transaction Set Requirements
  - Identify Processes with EDI Transactions
  - Estimate High Level Data Volumes for EDI Transactions By Process
  - Estimate High Level Data Volumes for Load Profiling and Settlement Processes

• **Business Separation**
  - Preferential Treatment
  - Separation of Employees
  - Emergency Circumstances
  - Advertising
  - Brand Image
  - Functional Separation
  - Joint Transactions
  - Reporting

• **Power Delivery**
  - Metered New Sets
  - Non-Metered New Sets
  - Existing Services
TO: Interested Parties

FROM: Fairbank, Maslin, Maullin & Associates

DATE: May 27, 2004

RE: Opinion Survey of OG&E Large Volume Customers in Arkansas

Oklahoma Gas & Electric Company (OG&E) commissioned a survey of 20 of its largest load customers in Arkansas relative to the perceived effects of having direct retail access to electric power.¹ Eighteen of the 20 large load users responded to the survey during the May 19 through 26, 2004 interview period.

**TWO CRITICAL ISSUES: FEASIBILITY AND COST SHIFTING**

Large load customers have uncertain views regarding the feasibility of a large user direct access rule allowing large users to choose to contract directly for electric power with non-regulated power generators at market rates. When asked whether a direct access program is feasible, only five said it “definitely” would be. Another five said “probably feasible,” while six said that they need more information than they currently have available in order to offer an opinion. Two respondents said such a program would “definitely” not be feasible.

Moreover, among the ten respondents who said a large user direct access program is either definitely or probably feasible, four said it is “probably not possible” to insure that a direct access program would not lead to cost shifting to residential and commercial customers. Another four said it is “probably” would be possible to give this assurance, but only one respondent said it is “definitely” possible to avoid cost shifting to other consumer sectors. One of the ten saying direct access is feasible also said that more information is needed before he could offer an opinion whether cost shifting would be avoidable.

¹ The survey was conducted by Fairbank, Maslin, Maullin & Associates, and independent opinion research company specializing in public policy issues. Interviews were conducted by telephone with a company executive responsible for operations at each OG&E large load customer responding to the survey. Thirteen of the responding companies had electric loads greater than 1,000 kilowatts; five respondents were uncertain of load size.
In sum, on the feasibility and cost shifting issues, only one respondent said it was both feasible to have a large user direct access program and "definitely" avoid cost shifting to residential and commercial customers. Four others said direct access is feasible but cost shifting to other customer classes is probably unavoidable. Four more who think direct access is feasible also said direct access could "probably" be done without cost shifting to other customer classes. Finally, one of the respondents who believe direct access is feasible also said he could not offer an opinion on the cost shifting issue without more information.

**DIRECT ACCESS AND RATES**

Opinions are mixed regarding the effect on residential and commercial electric rates of having a large user direct access rule. Seven of the 18 respondents believe electric rates will rise for residential and commercial customers if a large users' direct access rule is adopted. Five believe residential and commercial rates will not be affected, one way of the other, while three say these rates will decrease. Three others need more information before they can offer an opinion.

**AWARENESS OF AND PREPARATION FOR DIRECT ACCESS**

Fifteen of the 18 respondents had not heard or seen anything about the Electric Utility Reform Act of 2003 prior to participating in this survey. Further, a very small proportion of the large users contacted for this survey have undertaken a cost/benefit study comparing administrative costs associated with managing a direct access program with the cost of having a regulated utility company provides these services. Only two said their company had conducted such a study, one was unsure and 15 said that no such study as yet had been undertaken. Nine respondents said their company would look to an outside contractor for direct access management services while five said in-house employees would do the job. Four are uncertain and need more information prior to answering.

**SHIFTING BETWEEN THE MARKET AND REGULATED SYSTEMS**

Thirteen of the survey’s respondents believe that large load users should "definitely" be permitted to switch back and forth at will between non-regulated power markets and the regulated system. Two said "probably," and three are uncertain and want for information before offering and opinion. When asked to identify the size of load that would qualify a large user for a direct access program in Arkansas, 11 of the 18 respondents said they did not now what should be appropriate qualifying load. One said it should be the top 20 percent of customers and another said the top ten percent. Other responses were a million KWH per month, a half million KWH per month, 250 thousand KWH per month, one million KW and one hundred thousand KW.

**CONCLUSIONS**

This survey shows that there not a clear consensus on or standard for the electric load that would qualify an electric power customer as a large user. Further, there is no effective consensus among respondents to this survey on the feasibility of a direct access rule in Arkansas that would
also assure that costs would not be shifted to residential and commercial customers as a consequence of direct access.
Hello, I'm calling from Fairbank, Maslin, Maullin & Associates, a public opinion research company. We are definitely not telemarketers trying to sell you anything or ask for a donation. We have been asked by the Oklahoma Gas & Electric Company to conduct an opinion survey of large volume electricity users as part of a consultative process required by Arkansas law. This study is being directed by Dr. Richard Maullin, a partner in the opinion research firm. His contact information is available upon request. Responses to this survey will be aggregated for analysis, and all individual interviews will be kept completely confidential and not be used for any purpose other than contributing to the aggregate results. The survey will not take long; may I begin?

1. First, have you seen or heard anything about the Electric Utility Regulatory Reform Act of 2003, enacted by the State of Arkansas last year?

   Yes, heard of it------------------------1
   No, not heard of it -------------------2
   (DON'T READ) DK/NA -------------------3

2. The Electric Utility Regulatory Reform Act of 2003 repealed an earlier state law which initiated competition in the retail electricity market in Arkansas. The new law enacted last year asks the Arkansas Public Service Commission to study the feasibility of a large user access program for electric service choice. In your opinion, is a large user access program, in which large users can choose to contract for electric power supplied by a non-regulated power generator, feasible or not feasible in Arkansas? If you don’t have enough information about this issue to express an opinion, you can tell me that too. (IF FEASIBLE/NOT FEASIBLE, ASK: “Is that definitely or just probably?”)

   Definitely feasible (ASK Q. 3)----------1
   Probably feasible (ASK Q. 3)---------2
   Probably not feasible (SKIP TO Q. 4) 3
   Definitely not feasible (SKIP TO Q. 4) 4
   Need more info before offering an opinion (SKIP TO Q. 4)------------------5
   (DON'T READ) DK/NA (SKIP TO Q.4) 5
IF FEASIBLE IN Q. 2, ASK:

3. If a large user access rule were adopted by the Arkansas Public Service Commission, do you think it would be possible to insure that there would be no cost shifting to any other class of customers, such as residential or commercial, who would be wholly dependent on regulated utilities for electric service? Again, if you need more information to offer an opinion, or don’t know, you can tell me that too. (IF YES/NO, ASK: “Is that definitely or just probably?”)

   Definitely yes ---------------------------------------- 1
   Probably yes ---------------------------------------- 2
   Probably no ---------------------------------------- 3
   Definitely no ---------------------------------------- 4
   Need more info before offering an opinion-5
   (DON’T READ) DK/NA ---------------------------------- 5

ASK EVERYONE

4. If a rule allowing direct access for large volume electricity users were adopted in Arkansas, in your opinion, do you think residential and commercial electric rates would be increase, decrease, or would there be no effect one way of the other? If you need more information or are not sure, you can tell me that too.

   Increase ---------------------------------------- 1
   No effect ---------------------------------------- 2
   Decrease ---------------------------------------- 3
   Need more info before offering an opinion-5
   (DON’T READ) DK/NA ---------------------------------- 5

5. If the Arkansas Public Service Commission were to adopt rules for a large user access program, should large users be required to make a one-time choice to secure power from a non-regulated power generator, with no right to return to the regulated utility system, or should large users be permitted to switch back and forth between non-regulated power markets and the regulated utility system? Once more, if don’t know or need more information to have an opinion, you can tell me that too. (IF ONE-TIME CHOICE/SWITCH BACK AND FORTH, ASK: “Is that definitely or just probably?”)

   Definitely one time ---------------------------------------- 1
   Probably one time ---------------------------------------- 2
   Probably switch ---------------------------------------- 3
   Definitely switch ---------------------------------------- 4
   (DON’T READ) Need more info before offering an opinion-5
   (DON’T READ) DK/NA ---------------------------------- 5

6. Do you have an opinion on the size of a large user’s electric load, expressed in kilowatts, that would qualify it as a large user for purposes of a Arkansas Public Service Commission’ rule on direct access to a non-regulated power generator? (ASK FOR NUMBER; RECORD “DON’T KNOW” IF NO NUMBER OFFERED)
7. Assuming a large user direct access rule were adopted by the Arkansas Public Service Commission, would your company have an in-house employee or staff handle such tasks as dynamic load scheduling, transmission scheduling and risk mitigation, or would you contract for such services?

   In-house employee/staff------------------------1
   Contract--------------------------------------2
   (DON'T READ) Need more info before
   offering an opinion------------------------3
   (DON'T READ) DK/NA------------------------4

8. Has your company conducted a cost/benefit study that compares the increased administrative cost associated with scheduling energy and transmission services, risk mitigation and ancillary services such as imbalance charges and load following with the cost of having a regulated utility company provide these services?

   Yes------------------------------------------1
   No------------------------------------------2
   (DON'T READ) DK/NA------------------------3

10. In a few of your own words, could you tell me what is your company’s principal business?


12. Can you tell me the name of the Arkansas county where the majority of your company’s operations are located?


13. Could you estimate the average monthly electric load for your company expressed in kilowatts? (OPEN-END, DO NOT READ PRE-CODED RESPONSES)

   0-50------------------------------------------1
   51-100----------------------------------------2
   101-300---------------------------------------3
   301-500---------------------------------------4
   501-1,000-------------------------------------5
   More than 1,000-------------------------------6
   Don’t Know/NA--------------------------------7

THANK YOU VERY MUCH FOR YOUR TIME AND FOR ANSWERING OUR QUESTIONS
CERTIFICATE OF SERVICE

I, Lawrence E. Chisenhall, Jr., do hereby certify that I have served a copy of the foregoing instrument upon all parties of record via U.S. Mail, postage prepaid, this 28th day of May, 2004.

[Signature]

Lawrence E. Chisenhall, Jr.