UTILITY DISTRIBUTION TRANSFORMERS IN A RESTRUCTURED INDUSTRY: IMPLICATIONS FOR EFFICIENCY

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Introduction

As the electric industry restructures, many utilities are looking for ways to cut costs to gain a competitive advantage. Given the uncertainty of the market place, purchasing practices once characterized by a long-range view (e.g., lifecycle costing) are being reconsidered. Changes in utility distribution transformer purchasing practices could result in efficiency reductions and significant lost opportunities for energy savings. To better understand how retail competition is affecting utility distribution transformer purchases and the implications for energy efficiency, ACEEE performed a study, the results of which are presented in this report. In the summer and fall of 1998, ACEEE conducted interviews of utility distribution engineers and purchasing decision-makers to determine current practices in the purchase of distribution transformers. In addition, projected trends and shifts in purchasing practices in response to restructuring in the electric utility industry were investigated. This report outlines the scope and results of our findings.

Background

Restructuring of the electric utility industry, including the introduction of competition into what has been a monopoly-dominated market sector, is leading to profound changes in the way utilities operate and make business decisions. For distribution companies, restructuring is likely to mean an end to "rate of return" regulation and integrated resource planning and the advent of new market conditions allowing for increasing profits with increasing electricity sales. Furthermore, as utilities begin competing for retail customers, the challenge of offering the lowest rates will be met in part by short-term cost-cutting, including reductions in capital equipment expenditures.

As a result, utilities may purchase equipment that is less than optimal for the assigned applications, which, in turn, may increase stress on the distribution system, potentially reduce system reliability, and tax the generation system (Kushler and Suozzo 1999). While these actions run counter to smart business decision-making, numerous utilities — particularly smaller companies — are unsure of how long they will be able to survive and operate in the new business climate and, as a result, short-term cost-cutting appears to make sense. These actions are evidenced in part by shifts from life-cycle costing toward first cost purchasing criteria for distribution transformers.

U.S. utilities own an estimated 40 million liquid-immersed distribution transformers. Losses in the generation and delivery of electricity due to utility distribution transformers total 61 billion kilowatt-hours (kWh) annually. Recognizing the cost of these losses, most utilities have used a total owning cost (TOC) method, which accounts for capital and operating costs over the life of the transformers (i.e., typically 30 years), to evaluate transformer purchases. Transformers with the lowest TOC — the most efficient transformers with the minimum overall

cost — were purchased. Largely due to the application of a lowest TOC selection criteria, the full-load efficiency of liquid-immersed transformers purchased by utilities has improved over the years, from approximately 98.5 percent in 1970 to about 98.9 percent in 1996 (the latest year for which data are available) (Barnes et al. 1996).

Transformer losses are inherent to the technology and occur in two ways. First, because transformers are constantly energized, no-load or core losses occur all the time. Additional losses occur as a function of the load — greater losses are associated with greater loads. Improvement in the design and materials of both core and windings can reduce no-load losses and load losses, respectively. For example, the amorphous metal used in some transformer cores results in savings of 65 to 70 percent relative to standard transformers (Nadel 1994). Transformer efficiency is reported at full-load; however, the units often are operated under part-load conditions where efficiency is lower. This, plus the fact that transformers are energized 24 hour per day, means even small improvements in efficiency translate into big overall savings.

To help guide utilities in using the TOC methodology, the National Electrical Manufacturers Association (NEMA) adopted Standard TP-1 as the industry standard for efficient transformers.[1] TP-1 outlines two approaches for utilities to purchase efficient products: specifying lowest TOC products or using a default look-up table based on an approximately 3-year payback. The 3-year payback is very conservative for the 30-year lifetime of transformer products, so specification of the lowest TOC is preferred because it will generally lead to the purchase of a more efficient transformer.

Approach

In order to get a sense of current and future utility purchasing practices, ACEEE developed a list of 10 publicly owned utilities, 60 investor-owned utilities (IOUs), and 8 utility holding companies[2] throughout the United States. We then segmented the market according to three factors — size, status of state restructuring legislation, and ownership — to see how each factor may be impacting purchasing decisions. Appendix A provides the utilities included in our original list, along with size ranking, state legislation status, and the number of distribution transformers in operation. Thirty-three utilities from this list, accounting for a total of more than 7 million transformers, were surveyed. Appendix B contains the questionnaire that was used to survey utility representatives participating in the study.

[1] NEMA Standards Publication TP 1-1996, *Guide for Determining Efficiency for Distribution Transformers.*

[2] These eight holding companies represent a total of 29 operating companies. Each of these holding companies have standardized transformer purchasing practices among their subsidiaries.

In terms of size, the utilities were divided into quintiles corresponding to sales to end-use customers relative to all U.S. utilities. The utilities surveyed are among the larger U.S. utilities (i.e., within the top 60 percent of utilities by size) with 16 in the top quintile, 11 in the second quintile, and 6 in the third quintile. Twelve of the utilities surveyed operate in states where restructuring legislation was passed or final regulatory orders were issued. Fourteen utilities operate in states where, in our estimation, restructuring legislation is likely to be passed within the next 2 years. And nine utilities operate in states where restructuring legislation is considered unlikely to pass within the next 2 years.[3] Twenty-nine IOUs and four publicly owned utilities participated.

CURRENT TRANSFORMER PURCHASING PRACTICES

As suggested above, the methods used by utilities to evaluate transformer designs influence the efficiency of the units ultimately purchased and, given the typical 30-year transformer life, impact the efficiency of the distribution system for many years. Since the early 1980s, most utilities have used the TOC method when evaluating transformer purchases. This method balances the initial purchase cost of the transformer with the long-term cost of the energy losses incurred by the transformer. Utility purchasers specify loss evaluation factors (A&B values) used in determining TOC based on the specific application and conditions in which the transformer will be operated. A&B values are a measure of the costs of transformer losses in dollars per watt. The A value reflects the cost of core (or no-load) losses, which is approximated by baseload energy costs. The B value reflects winding (or load) losses, which also consider transformer loading.

Many utilities using the TOC method also apply a band of equivalence (BOE) when making purchasing decisions. The BOE is designed to account for uncertainties in the loss factors used in determining TOC — fuel costs, interest rates, inflation — and allows purchasers to choose among transformers that fall within a certain range of TOC. Generally, a BOE of 1 to 5 percent is applied to the lowest TOC.

Utilities surveyed were asked to provide details of their current purchasing practices, including purchasing criteria (e.g., TOC, payback, etc.), manufacturer alliances, details of how the criteria are implemented, and decision-making structure.

[3] The number of companies operating both in states where restructuring legislation is considered likely and where it is considered unlikely include a subset of the large holding company subsidiaries; as a result the total number adds up to more than the total number surveyed.

Purchasing Criteria

Participants were asked several questions about their transformer purchasing criteria, including whether they use TOC or some other method, whether they apply a BOE to the TOC, etc. Table 1 summarizes the responses to these questions. In this study, virtually all of the utilities surveyed (i.e., 31 out of 33) use the TOC method. Of these, 13 use a strict TOC method (also referred to as a "hard approach") while 18 apply a BOE to the TOC (also known as a "soft approach"). The use of the BOE allows utilities to make a trade-off of efficiency for first cost, typically leading to the purchase of less than maximally efficient transformers. Of these 18 utilities, one uses a modified TOC method (with a 3 percent BOE) that also incorporates vendor and materials factors in cost calculations, while another uses first cost criteria in addition to TOC when making a limited number of its purchasing decisions, as decided on a case-by-case basis. The two utilities that don't use TOC use either an annual owning cost method with 5 percent BOE or a unique method whereby the purchasing department uses specifications developed by the engineering department to acquire transformers based on price, availability, and service criteria.

Among the 18 utilities using the TOC method with a BOE, 16 apply a 3 percent window and 2 apply a 5 percent window. Both of these utilities are among the largest utilities (i.e., in the first quintile). Nine of these 18 utilities began applying a BOE within the past 5 years. The one utility using an annual owning cost method also applies a 5 percent BOE and ranks among the top 20 percent of utilities by size.

Twelve companies using the TOC method declined to provide their A&B values when surveyed. However, one of these commented that their values are "higher than most." Reported A&B values range from $0.69/watt to $5.45/watt (A values) and $0.29/watt to $2.15/watt (B values). Regional energy costs are relevant in determining the A&B values for individual utilities and play a part in the large range of values reported. For instance, utilities operating in the Northeast and Southwest typically reported higher A&B values than those in other regions of the country.

Table 1: Summary of Utility Transformer Purchasing Criteria

		A&B Values for Utilities Using TOC ($/watt)			
Purchasing method	**n**	**A values**	**n**	**B values**	**n**
Strict TOC	13	≤ $1.00	1	≤ $0.50	2
TOC w/ 3% BOE	16	$1.01 to $2.00	2	$0.51 to $1.00	9
TOC w/ 5% BOE	2	$2.01 to $3.00	9	$1.01 to $1.50	5
Annual Owning Cost w/5% BOE	1	$3.01 to $4.00	2	$1.51 to $2.00	2
Other	1	> $4.00	5	> $2.00	1
		MEAN	3.00		1.00
		MEDIAN	2.78		0.93

Manufacturer Alliances

Eighteen respondents have established manufacturer alliances or lengthened the terms of their contracts with transformer manufacturers. This number includes two publicly owned utilities that have extended their contract periods as long as possible under the restrictions they face as public entities. Both of these utilities expressed an interest in establishing alliances or extending their contracts for even longer periods. The majority of these alliances were set up in the past 2 to 6 years. Advantages of these alliances include better pricing, more certainty of pricing and product availability, reduced on-site inventory, and improved predictability of product quality and delivery. A majority of these utilities have entered into alliances with at least two manufacturers.

Decision-Making

Responsibility for establishing transformer purchasing criteria falls to the engineering or standards departments in 26 of the utilities surveyed. The financing and purchasing staffs often have input into the process. The planning and procurement departments of two utilities establish the criteria. Another utility has a special planning group, composed mainly of engineers, to set purchasing decision criteria. At the remaining four utilities, purchasing criteria are determined by: (1) statistical analysis division; (2) corporate finance; (3) purchasing; or (4) the Director of Supply Chain.

ENERGY STAR® Participation and Program Awareness

Survey questions regarding the ENERGY STAR transformers program were not consistently asked in the utility interviews. With the utilities that were questioned, responses were limited on changes to the ENERGY STAR program that would encourage non-participants to participate. Of the 24 utilities that were asked these questions, 3 participate in the program. Almost all of the utilities that were asked about the program but do not participate are aware of the program. A lack of resources or willingness to meet the reporting requirements and technical constraints were most often cited as reasons for non-participation. One representative from a smaller utility noted that although his utility meets the criteria, the utility is not interested in a time-consuming, voluntary program when they are working just to stay alive in the changing industry. Additional reasons included the perception that there are few incentives and unclear benefits from participation, particularly for larger utilities. A respondent from one of the largest utilities expressed the view that EPA and the utilities "are moving in different directions."

CHANGES IN TRANSFORMER PURCHASING PRACTICES

Restructuring is increasingly a driving force influencing decision-making in the utility industry. As competition is introduced, efforts to cut costs and make decisions based on shorter

business cycles become more commonplace. The utilities surveyed were asked about any changes in purchasing practices that have been instituted in the past 5 years, the role of deregulation in their decision-making, and what changes are anticipated in the face of the uncertainties arising from restructuring.

Changes to Date

Twenty-one utilities surveyed reported that purchasing practices had changed in the past 5 years. Of these, seven stated that these changes were due to deregulation; three of these utilities operate in states where restructuring legislation has passed and four operate in states where legislation is considered likely to pass in the next 2 years. Approximately one-half of the largest utilities surveyed reported changes to date, whereas more than two-thirds of the utilities from the second and third quintile reported changes. The changes implemented to date include:

- establishment of manufacturer alliances or longer contracts (15 utilities);
- application of BOE (9 utilities);
- standardization of transformer designs (5 utilities, including 2 large utility holding companies);
- reduction of transformer life in lifecycle calculations from 30 years to 20 years (3 utilities); and
- increase in size of BOE from 3 to 5 percent (1 utility).

Of these changes, those most commonly cited as a response to deregulation include manufacturer alliances, application of BOE, and a growing first cost focus resulting in lowering of A&B values. Indeed, a number of utilities have recently reevaluated their A&B values for the first time in 10 years or more. While the survey included "lowering A&B values" as an example of possible changes in purchasing practices, respondents did not explicitly list it as one of the changes that had been implemented. Several of the smaller publicly owned utilities declared an interest in establishing manufacturer alliances or working out much longer contract terms with manufacturers and suppliers, but cited restrictions to these actions based on their public status.

Changes Anticipated

Twenty utilities reported anticipated changes in their purchasing practices. Of these, 16 stated that these changes will be made in response to deregulation in the electric utility industry. The changes under consideration include:

- adopting payback or strict first cost criteria to replace TOC (8 utilities);
- applying a BOE if not already in use (5 utilities);
- reducing transformer life for TOC calculations — typically from the traditional 30 years to 15-20 years (5 utilities);

- lowering loss values in the TOC calculation (4 utilities);
- forming strategic alliances or longer contracts with transformer manufacturers (4 utilities); and
- standardizing transformer designs (3 utilities).

Two utilities that did not anticipate any major changes at the present time stated that a gradual decrease in A&B values and a shift from TOC to strict first cost criteria are possible. A few of the respondents expressed their belief that the shift to a focus on lower first costs would impact the transformer technologies used. For instance, one utility is discontinuing research on amorphous silicon core transformers.

Of the 12 respondents operating in states where restructuring legislation has passed, 2 report that no major changes have been made and none are anticipated as a result of restructuring, 5 have made a number of changes but do not anticipate any additional changes, and 5 anticipate a number of changes in addition to some that have already been implemented. In general, the smaller utilities report more drastic changes — including dropping the TOC method in favor of first cost or payback criteria — and more concern about the impact of restructuring than the larger utilities.

DISCUSSION

The responses to our survey demonstrate the uncertainty associated with the evolving utility industry. Almost two-thirds of the utilities surveyed have implemented changes to their purchasing practices in the past 5 years. The utilities reported that these changes were made to reduce costs, adapt to changes in the market, and enhance competitiveness. Further discussion analyzes the survey responses by utility size, the status of state restructuring legislation, and utility ownership structure.

Utility Size

The original list of utilities compiled for this study consisted of 30 utilities from the first quintile, 19 from the second quintile, 22 from the third quintile, and 7 from the fourth quintile. Of these, participation in our survey breaks down as follows: 16 from the first quintile; 11 from the second quintile; and 6 from the third quintile. No utilities from the fourth quintile were successfully surveyed. Table 2 summarizes the survey findings by utility size.

As Table 2 demonstrates, purchasing criteria are generally consistent among utilities of each size class. For the most part, strict TOC or TOC with a 3 percent BOE is being used; however, some of the larger utilities are applying a 5 percent BOE or using other criteria. (It should be noted that the small sample size of utilities in the third quintile may not adequately account for practices among utilities of that size.) In addition, only two of the largest utilities

applied a 5 percent BOE, the remainder of those using a soft approach applied a 3 percent BOE. On average, the larger utilities used smaller A&B values, with mean A&B values being highest for those in the third quintile. Half of the largest utilities surveyed and just over half of the second quintile utilities have entered into alliances, while one of those without alliances is considering it for the future. In the third quintile, 4 of the 6 respondents — including the 2 publicly owned utilities mentioned above — have established alliances or longer-term contracts.

Smaller utilities expressed the greatest concern over changes in the electric utility industry and their uncertainty about maintaining their competitiveness in a deregulated environment. Approximately half of the first and second quintile utilities reported that they had made changes to their purchasing practices in response to deregulation and that they anticipated further changes as the process continues. All but one (i.e., 5 out of 6) of the third quintile utilities made the same statements. Three of these utilities reported that changes under consideration include a shift away from TOC to first cost or payback criteria.

Table 2: Summary of Survey Results by Utility Size

Quintile	n	Current Practice	Manufacturer Alliances	A&B Values ($/watt)
First	16	Strict TOC = 6 TOC w/3% BOE = 6 TOC w/5% BOE = 2 Other = 2	Yes = 8 No = 8	A = $0.69 to $3.20 (avg = $2.16) B = $0.41 to $1.17 (avg = $0.72)
Second	11	Strict TOC = 3 TOC w/3% BOE = 8	Yes = 6 No = 5	A = $1.79 to $5.45 (avg = $3.30) B = $0.29 to $1.89 (avg = $0.96)
Third	6	Strict TOC = 4 TOC w/3% BOE = 2	Yes = 4 No = 2	A = $2.50 to $4.95 (avg = $3.69) B = $0.60 to $2.15 (avg = $1.36)

Status of Restructuring Legislation

The status of state restructuring legislation was broken down as follows: legislation unlikely in the next 2 years; legislation passed; or legislation likely in the next 2 years. Of the original list of 78 utility companies compiled for this study, 29 operate in states where restructuring legislation has passed, 29 operate in states where legislation is considered likely to pass in the next 2 years, and 22 operate in states where legislation is considered unlikely to pass in the coming 2 years. From these, survey participants represent: 12 utilities operating in states where legislation has passed; 14 utilities where legislation is considered likely; and 9 utilities

where legislation is considered unlikely. Table 3 summarizes survey findings according to the status of state legislation.

Table 3: Summary of Survey Results by Legislation Status

Legislation Status	n	Current Practice	Manufacturer Alliances	A&B Values ($/watt)
Passed	12	Strict TOC = 4 TOC w/3% BOE = 7 TOC w/5% BOE = 1	Yes = 7 No = 5	A = $0.69 to $5.45 (avg = $3.03) B = $0.51 to $1.46 (avg = $0.94)
Likely	14	Strict TOC = 6 TOC w/3% BOE = 5 TOC w/5% BOE = 1 Other = 2	Yes = 8 No = 6	A = $1.74 to $4.95 (avg = $3.18) B = $0.41 to $2.15 (avg = $1.16)
Unlikely	9	Strict TOC = 2 TOC w/3% BOE = 6 Other = 1	Yes = 4 No = 5	A = $1.79 to $2.78 (avg = $2.47) B = $0.29 to $1.28 (avg = $0.65)

Utilities across the board reported that they have made changes to their purchasing practices and/or anticipate further changes in response to deregulation and the changing marketplace. This applies even to utilities operating in states where it is unlikely that legislation to deregulate the industry will be passed in the next 2 years. Given that federal legislation on utility restructuring is pending, the entire industry is facing the issue of competition regardless of the status of restructuring in individual states.

Specifically, only two utilities operating in states where legislation has passed reported that no major changes have been implemented in their purchasing practices and that none are anticipated. The remaining 10 utilities in this group have all instituted changes; five of these anticipate that additional changes will be made. Among the 14 utilities operating in states where legislation is likely to be passed, five have not implemented any changes and two of these do not expect to do so in the future. Of the three anticipating change, two attribute these changes to deregulation. Nine utilities in these states have implemented changes to date; six expect to make additional changes due to deregulation. And in states where legislation is considered unlikely, three utilities have not made changes to date but expect changes to be implemented. Two attribute these expectations to deregulation. Four have made changes to their purchasing practices; three anticipate additional changes, of which two reported the changes are being instigated by deregulation. In addition, those utilities in states unlikely to pass legislation have lower average A&B values. A 5 percent BOE was only found in utilities operating in states that have passed or are likely to pass legislation.

Ownership Structure

Twenty-five of the 60 investor-owned utilities included in our original list of utilities participated in the survey. This group represents utilities in each of the top three quintiles by size. Of the eight utility holding companies on the list, four participated in our survey. Each of these have standardized purchasing criteria among their subsidiary utilities. Four of the 10 publicly owned utilities from our original list participated in our survey. Two operate in a state where restructuring legislation has passed while two operate in states where legislation is considered likely.

In general, purchasing criteria were similar for the utilities regardless of ownership structure. Two of the smaller publicly owned utilities reported that their ownership status limited their flexibility in negotiating long-term contracts or establishing alliances with transformer manufacturers. These utilities reported that these constraints might negatively affect their competitiveness in a deregulated environment. Three of the four utility holding companies reported that they have not changed their purchasing practices in light of deregulation and do not expect deregulation to impact their purchasing practices in the future. These three companies have subsidiaries operating in different states and have set up standardized purchasing practices.

CONCLUSIONS

Over the past several years, many utilities have begun implementing changes in their transformer purchasing practices. These changes have been designed to cut costs and improve utility competitiveness in response to changes in the electric utility industry and uncertainty over the future as deregulation impacts the market. A number of these changes (including application of a BOE to the TOC purchasing criteria, shortened life cycles for purchasing decisions, and a shifting focus to first cost principles) have a negative affect on the efficiency of transformers purchased and, therefore, represent lost opportunities for energy savings. Although most utilities in the study reported that they anticipate further changes, there is considerable uncertainty over the exact changes that will be implemented. The greatest concern about these changes was expressed by the smaller utilities participating in the survey. Further investigation into methods for addressing these concerns, tools for working with utilities of all sizes, and policies for promoting efficient transformers at the state and federal level is warranted to ensure that the efficiency gains that have been made are not reversed.

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APPENDIX A: ORIGINAL POOL OF UTILITIES FOR SURVEY[○]

Utility Name	State(s)	Size	Status[#]
Investor-Owned Utilities			
American Electric Power*	OH, IN, WV, VA, KY, MI, TN	1	L/U
Arizona Public Service Co.	AZ	2	P
Atlantic City Electric Co.	NJ	3	L[†]
Baltimore Gas & Electric Co.	MD	1	L
Boston Edison Co.	MA	2	P
Carolina Power & Light Co.	NC	1	U
Central Hudson Gas & Electric Corp.	NY	3	P
Central Illinois Public Service Co.	IL	3	P
Central Maine Power Co.	ME	3	P
Central Vermont Public Service Corp.	VT	4	L
Cinergy	IN, OH	2	L
Commonwealth Edison Co.	IL	1	P
Commonwealth Electric Co.	MA	3	P
Consolidated Edison	NY	1	P
Consumers Energy	MI	1	L
Delmarva Power & Light Co.	DE	2	L
Detroit Edison	MI	1	L
Duke Power Co.*	NC	1	U
Eastern Edison Co.	MA	4	P
El Paso Electric Co.	TX	3	L
Entergy Corp.*	LA, TX, MS, AR	1	L/U
Florida Power & Light Co.	FL	1	U
Green Mountain Power Corp.	VT	4	L
Gulf Power Co.	FL	3	U
Houston Lighting & Power Co.	TX	1	L
Indianapolis Power & Light Co.	IN	2	L
Kansas City Power & Light Co.	MO	2	U
Kentucky Utilities Co.	KY	2	U
Louisville Gas & Electric Co.	KY	2	U
Madison Gas and Electric Co.	WI	4	L
Massachusetts Electric Co.	MA	2	P
Minnesota Power & Light Co.	MN	2	U
Montana Power Co.	MT	3	P
Nevada Power Co.	NV	2	P
New England Electric System*	MA, NH, RI	1	P
New York State Electric & Gas	NY	2	P
Niagara Mohawk Power Corp.	NY	1	P
Northeast Utilities*	CT, MA, NH	1	P
Northern States Power	MN	1	U
Northwestern Public Service Co.	SD	4	U
Ohio Edison Co.	OH	1	L
Investor-Owned Utilities (cont'd)			

Orange and Rockland Utilities	NY	4	P
Otter Tail Power Co.	MN	4	U
Pacific Gas & Electric Co.	CA	1	P
PacificCorp	OR	1	L
Pennsylvania Power & Light Co.	PA	1	P
Portland General Electric*	OR	2	L
Potomac Electric Power Co.	DC	1	U
Public Service Company of New Hampshire	NH	3	P
Public Service Company of New Mexico	NM	3	U†
Public Service Electric & Gas	NJ	1	L†
Public Service of Colorado	CO	1	U
Puget Sound Power & Light Co.	WA	1	L
Rochester Gas and Electric Corp.	NY	3	P
San Diego Gas & Electric Co.	CA	2	P
Sierra Pacific Power Co.	NV	3	P
South Carolina Elec & Gas Co.	SC	2	U
Southern California Edison Co.	CA	1	P
Southern Co.*	GA, AL, FL, MS	1	U
Texas Utilities Electric Co.	TX	1	L
Toledo Edison Co.	OH	3	L
Tucson Electric Power Co.	AZ	3	P
Union Electric Co.	MO	1	U
Virginia Electric & Power Co.	VA	1	L†
Washington Water Power Co.	WA	3	L
Wisconsin Electric Power Co.*	WI	1	L
Wisconsin Power & Light	WI	3	L
Wisconsin Public Service Corp.	WI	3	L
Publicly Owned Utilities			
City of Austin	TX	3	L
Jacksonville Electric Authority	FL	2	U
Los Angeles Department of Water and Power	CA	1	P
New York Power Authority	NY	2	P
Omaha Public Power District	NE	3	U
Sacramento Municipal Power District	CA	3	P
Salt River Project	AZ	2	P
San Antonio Public Service Board	TX	2	L
Seattle City Light	WA	3	L
South Carolina Public Service Authority	SC	3	U

○ 33 participants were drawn from this list.
P = legislation passed or regulation finalized; L = legislation likely in the next 2 years; U = legislation unlikely in the next 2 years.
*standardized purchasing criteria among subsidiaries
†notes that at the time of the survey, legislation was considered likely to pass and has since passed, (L†) or that at the time of the survey legislation was considered unlikely to pass but now considered likely (U†).

APPENDIX B: UTILITY QUESTIONNAIRE

1. What type of criteria is used to select among alternative distribution transformers for your system purchases?

- Total Owning Cost — if so, do you apply a band of equivalence or other means of altering from a strict TOC method; explain (e.g., what is the current BOE)? How often to do you adjust or recalculate A (no-load or core losses) & B (load losses) values? What are your current A&B values?

- Payback criteria — if so, what is the criteria and how is it established? Do accounting rules come into play for equipment purchased for the utility's system?

- Other methods

2. Who is responsible for establishing the selection criteria (e.g., A&B values for TOC, payback periods or hurdle rates) — i.e., strategic planning, distribution engineers, marketing strategists, accounting departments, others?

3. Has your approach for selecting among alternative distribution transformers changed significantly in the last 5 years (e.g., change in approach or change in A&B values)? If so, how has it changed, why was it changed, and when were the change(s) made?

4. Has the fact that the electric utility industry is deregulating affected your approach to purchasing distribution transformers (and perhaps other system equipment) (i.e., cost-cutting measures may result in dropping TOC, making the BOE bigger — 5% instead of 2 or 3%, reducing the payback period threshold).

5. How is your company approaching or planning to approach deregulation?

6. Do you anticipate changes to transformer purchase practices and criteria in the next few years? If so, what types of changes do you anticipate (e.g., move toward payback period type of analysis or toward lower or higher A&B values)?

7. Are you familiar with EPA's ENERGY STAR transformer program? Does your company participate in the program? Why do you participate or not participate? Do you have any suggestions on how the program could be improved to make it easier or more likely for your company to participate?

8. Are there other folks within your company with whom I should talk to better understand both current and future purchasing practices?