1REPORT ON CHANGES AFFECTING THE ELECTRIC UTILITY INDUSTRY

I.PROCEDURAL BACKGROUND

On January 30, 1996, the Idaho Public Utilities Commission (IPUC; Commission) issued Order No. 26312 and a Notice of Inquiry (NOI) in Case No. GNR-E-96-1.  On February 14, 1996 and March 19, 1996, the Commission conducted workshops to address several issues outlined by the Commission.  Over 50 individuals representing more than 20 organizations, attended each workshop.

Participants in these workshops have agreed that although consensus does not exist on all issues, a draft Report prepared by some of the participants, known as the “working group,” would be an appropriate means to identify issues facing the industry and possible courses of action available to the Commission.  This Report is the product of that working group.

II.INTRODUCTION

For much of the last 80 years, public utility regulation has been based on the idea of a regulatory compact between utilities and regulators under which, in return for an exclusive franchise granted by the state, utilities agree to serve all those requesting service; and in return for agreeing to invest capital in plant and facilities, utilities’ prices are set by regulators so that they are given a reasonable opportunity to earn a fair return on that capital.  Under the current regulatory regime, customers are grouped into fairly homogeneous classes and pay rates based on a variety of factors including the cost and value of the service to that class.  Rate setting considerations include simplicity, understandability, and public acceptability, the avoidance of sudden and unexpected changes, promotion of the efficient use of resources, and other social policies.

There are currently three major investor-owned electric utilities (IOUs) serving customers in Idaho.  They are Idaho Power Company, The Washington Water Power Company and PacifiCorp dba Utah Power & Light Company.  All three also serve customers in other states.  These utilities are regulated by the IPUC, other state commissions, and the Federal Energy Regulatory Commission (FERC).  Costs are allocated among the various retail and wholesale jurisdictions, with the IPUC setting retail rates for Idaho customers and FERC regulating wholesale transactions whether inter- or intra-state.  In addition to the IOUs, approximately 25 publicly-owned utilities provide service in Idaho.  These utilities’ retail rates are not regulated by the IPUC, but any wholesale transactions entered into by these utilities fall under the jurisdiction of FERC.

The IPUC regulates utilities under its authority found in Idaho Code, Titles 61 and 62.  Electric utilities are also subject to the Idaho Electric Supplier Stabilization Act, or ESSA, (Idaho Code  § 61-332 through 61-334B) designed to promote harmony within the Idaho electric industry, prohibit the pirating of customers of another supplier, discourage duplication of facilities, and stabilize service territories.

The enactment by Congress of the Public Utility Regulatory Policies Act (PURPA) in 1978 and, more recently, the Energy Policy Act of 1992 (EPACT) have changed the regulatory compact by encouraging competition in what were monopoly markets.  PURPA injected competition into the electric generation market by requiring utilities to buy the output of cogeneration and small power producers at the utilities' avoided costs.  EPACT further opened bulk power markets to competition by encouraging new wholesale generators and giving FERC broader authority to order open wholesale transmission access.  FERC responded by issuing a notice of proposed rulemaking, followed on April 24, 1996 by Final Order 888 designed to remove impediments to competition in wholesale bulk power markets.  Order 888 requires all jurisdictional utilities transmitting electric energy in interstate commerce to file open access non-discriminatory transmission tariffs, to take transmission service for their own wholesale sales and purchases under these tariffs, to develop and maintain a “same-time” information system (Open Access Same-Time Information System, OASIS) that gives others the same access to transmission information that the public utility itself enjoys, and to separate the marketing of transmission and generation.

These events, in combination with changes in technology and low natural gas prices, have brought about a significant transformation of the electric industry.  The changes taking place include increased third-party transmission access, the emergence of power marketers, and increased competitive pressures.  A driving force in creating these changes is customer interest in having a choice among electric service providers.  The business strategies of all of Idaho’s electric suppliers, including the three IOUs regulated by the IPUC, are changing to meet their customers needs and the new market conditions they face.

Many states have opened inquiries in response to this  movement toward a more competitive industry.  Many of the restructuring proposals being considered by other states focus on increased access to power markets for retail customers.  Many would permit retail wheeling.  An end-use customer would be permitted to shop for power on the open market or contract with a power marketer or aggregator to secure power for the customer.  The local utility would then be required to deliver, or “wheel,” the independently secured power to the retail customer's premises over the utility's facilities.  Because regulation of retail utility service is a matter of state law, individual state commission responses to emerging competition will necessarily differ.  States must also consider actions taken in their neighboring states.  Of major concern to western states has been the California PUC decision to allow customers to purchase power from a power pool called the “power exchange” with a limited group of customers allowed direct access.

The Commission, with the participation of a broad cross-section of stakeholders listed

in Attachment A, have been meeting to discuss this changing electric industry environment.  This Report, prepared by a working group consisting of some of those parties, attempts to outline the changes taking place in the industry and identify the decisions and options facing the Commission in the near future.  It offers a perspective on the underlying structural changes occurring in the electric industry, sets out policy questions the Commission will face as it considers electric utilities' transition to a more competitive environment, and identifies potential actions that can be taken to accommodate and capitalize on the benefits presented by this transformation.  A contemplated agenda is included in the Report.

The Report focuses on, and is unique to, customers of Idaho electric providers.  While the Commission has monitored proceedings in other states, the situation facing Idaho customers is unique.  Some Idaho customers pay the lowest rates in the country.  However, this distinction is shared by the customers of a number of hydro-electric utilities in the Northwest.  The challenge for the Idaho electric industry is to find advantages in a more competitive environment while maintaining the benefits that Idaho customers have historically enjoyed and expect to continue.

The changes occurring within the industry are, to varying degrees, already upon us.  Utilities have been responding to these changes on a filing-by-filing basis.  Examples include special contracts with large customers, rate freezes, demand-side management (DSM) tariff riders, and an experimental open access tariff.  We are now at a critical point, however, at which the Commission must reassess the practicality of the existing regulatory framework.  As noted, changes are occurring in the industry independent of any action taken by the Commission.  The primary focus of the Report, therefore, is to assist the Commission in identifying what obligations, authority, options, and role it has in the evolution toward a more market-based industry.

III.THRESHOLD ISSUES

Increased competition in the electric industry has been driven by changes in technology (e.g., more efficient and less costly turbines), economics (e.g., lower fuel costs for turbines), and public policy (e.g., recent changes implemented by FERC).  One result of these changes has been an increase in the supply of available power in the western electricity markets.  Market prices for firm power are now at or below utilities’ average, or embedded, cost of production for the first time in many years.

As a result of the Commission’s NOI and the workshops that have been conducted, it became apparent that there were several threshold issues that must be addressed by the Commission.  Those issues are discussed below.

1)Should the existing regulatory framework be altered?

In a competitive market, market power is distributed among a broad group of individual enterprises and operation of the market is driven by the independent decisions of  many buyers and sellers.  Because of the economies of scale inherent in many aspects of the public utility industry, it was once thought that utilities would operate most efficiently as monopolies.  The assumption that utilities were natural monopolies, combined with the high degree of public interest attached to utility services are the primary reasons for the public utility regulation we have today.

There is no bright line that identifies at what point a market becomes competitive enough to allow market forces to work.  It is now apparent, however, that competition is either present or inevitable in some functions of the electric industry.  As a result of PURPA and EPACT, the generation of power is no longer a monopoly function performed only by regulated utilities, and open transmission access means that utilities cannot use their own transmission facilities to gain an advantage in the wholesale generation market.  A robust wholesale power production market is now in place and a new category of participants has arisen with the advent of marketers such as Enron and Louis Dreyfus who own no generation assets or transmission lines but buy and sell power at wholesale.  Access to this market is now being demanded by some retail customers.

Initially, the Commission must determine whether the existing regulatory framework is adequate to accommodate the changing environment in which investor-owned utilities operate so that the needs of customers and utilities alike may be satisfied.

2)What actions could the Commission take to further the movement of the electric industry toward a market based environment?

Until there are changes in the Idaho Code, the Commission is somewhat limited in what it can do with respect to the deregulation of its regulated electric utilities.  If Idaho law were changed, the Commission could, conceivably, be faced with the choice of whether to deregulate the generation, transmission or distribution operations of Idaho’s regulated utilities and how to change regulation of the remaining function(s).  Under existing law, however, the Commission can still act in a number of ways to facilitate the transition to a competitive environment.  For example, the Commission currently has authority to consider cost recovery for stranded investment, demand-side management programs (DSM), and renewable energy sources, to eliminate any unreasonable cross subsidies where some customers pay rates above cost and others, rates below cost, and to address concerns about consumer protection and service quality in light of expected changes in the industry.  It can approve unbundled rates and give utilities more flexibility in dealing with customers.  It can adopt performance standards and examine its customer relations policies to determine whether modifications are necessary.  The potential actions that could be taken by the Commission are discussed in more detail under “Transaction Issues” below.

Some parties argue that the distribution (“wire”) functions of Idaho’s electric utilities are a natural monopoly and should remain regulated because of the social, environmental and economic shortcomings of redundant or competing distribution systems.  They contend that only through a regulated monopoly can important public policies be pursued.  Without sufficient Commission authority, the Commission could not avert bypass of the system and keep power affordable in the many rural communities of Idaho.

Other parties question the retention of protected service territories, saying that distribution service should not be assumed to be a natural monopoly.  They argue that while the assumption may have been true in an industry dominated by large central generating stations, it is no longer the case.  Furthermore, they believe the current design of the distribution system, typified by low-capacity factors, excess and idle circuit capacity, and a one-size-fits-all approach to power quality, makes it vulnerable to competition from hybrid systems designed to meet the power requirements of specific customers.  They argue that the current averaging of distribution costs to provide postage stamp rates available to customers in rural and urban areas alike distorts the cost of distribution to individual customers and increases the potential for uneconomic bypass of the system by large customers.  (Bypass is termed “uneconomic” when it occurs because the customer is charged more for service than the actual cost of that service.)  They also argue that cross-subsidization of high-cost areas by low-cost areas restricts competition by discouraging distributed resources that would otherwise be cost effective.  These parties would have the Commission stop the averaging of distribution costs and unbundle distribution rates.

Parties may disagree on whether transmission is a natural monopoly; however, this is not an issue to be decided by the IPUC.  FERC has claimed jurisdiction over all transmission for third parties with no distinction between retail and wholesale transactions.  Unless FERC is found to have overstated its jurisdiction, the IPUC’s authority over transmission will be confined to the transmission necessary to move power from utility-owned generation to its own retail customers.

A competitive generation market has been evolving since the passage of PURPA in 1978.  The Commission sets prices for mandatory purchases of power from facilities that qualify under PURPA (Qfs).  The methodology by which the Commission will establish rates for QF projects larger than 1MW is the subject matter of Case No. IPC-E-95-9 currently pending before the Commission.  All three investor-owned utilities regulated by this Commission have included an increasing reliance on market purchases in their integrated resources plans.  Publicly-owned utilities traditionally relying predominantly on the Bonneville Power Administration (BPA) for their power, have indicated an interest in diversifying their supply portfolios.

The Commission could, with changes in the law, deregulate the generation function of regulated electric utilities, which would allow utilities to sell their power at market rates outside as well as inside their current service territory in Idaho to end-use and wholesale customers.  Such a move would have to be preceded by legislation allowing customers to purchase power from their chosen provider and to wheel that power over the utility’s distribution system.  Issues associated with deregulation of generation would include stranded costs, “stranded benefits” associated with currently low-cost hydro generation facilities, and obligation to serve or “provider of last resort.”

3)If the Commission implements specific competitive measures, should all customer classes participate?

Some participants believe that increased competition in the wholesale markets will drive down the average cost of power passed on to all customers.  Additionally, utilities can be expected to become more administratively efficient as some load or customers become vulnerable to being served by other providers.  Ideally, these power-cost and administrative efficiencies should be to the benefit of all customers.

Some believe, however, that not all customers may benefit from replacing regulation with competition.  A more competitive environment, at least in the transition stages, may be advantageous only to those customers able and willing to risk the uncertainty of future price and availability.  In addition, some are concerned that those “core” customers for whom alternative sources of supply may not be readily available or are more costly should be treated differently than other customers.  “Core” customers would generally be residential and small commercial customers with much lower usage than industrial customers and who tend to use power during peak periods when market prices are higher.  These customers currently can rely on fairly stable rates; however, this stability may not be possible in a competitive environment.  Some believe these customers will wish to avoid the hassle of choosing from a number of electric suppliers and would prefer to rely on Commission oversight of a utility - obtained portfolio of resources to serve them.  Others disagree, saying that any number of energy service companies will be formed to provide small-to-medium customers with a whole range of energy service options.

It has been suggested that a gradual transition to competition should occur, starting with “experimental” tariffs available to industrial and possibly large commercial customers now clamoring for choice.   Others argue that it would be grossly unfair to allow large customers access to competitive markets before small-to-medium “core” customers.  They say these large industrial customers in Idaho already enjoy enviable rates that most certainly will come under upward pressure as the competitive forces expand to a larger, regional basis; however, current market conditions still allow some short term opportunities to improve their relative position before they lock in long-term contracts with their host utility. They argue that under the proposed scenario, those remaining on the utility system after the large customers leave would be burdened with responsibility to pay a greater share of the utility’s fixed costs without any opportunity to exercise the freedom of choice enjoyed by their larger brethren.  They suggest that small-to-medium customers may be able to aggregate their loads and obtain special contracts in the same manner as large customers and are adamant that any experimental programs be available to customers across all classes.

To the extent that the Commission considers implementing any proactive measures designed to foster competition in Idaho, in one form or another, it must decide to whom those measures apply and consider the effects on those unable to acquire alternative sources of electric service.  As the market evolves, options for all customer classes should be preserved to the extent possible, so that no class is foreclosed from enjoying the benefits of competition.

IV.SPECIFIC TRANSITION ISSUES

Nine issues were framed in the first two workshops conducted by the Commission which require regulatory or legislative attention as the electric industry continues its transition.  Success in this docket by the Commission can, in many ways, be achieved through the development of a plan for resolution of both traditional and emerging issues.  The following discussion links the nine issues with specific regulatory items.  It does not appear that consensus can be reached on a number of these issues.

A.State and Federal legislation.

Some changes may be needed to Idaho’s existing laws and regulations.  First, the Electric Supplier Stabilization Act (Idaho Code §61-332 through 61-334B) may need to be revisited.  Second, regarding the IPUC regulatory authority (Idaho Code, Title 61) to respond to industry change, some parties believe that the Commission currently has sufficient legislative authority to manage evolving market structure as described in the above comments.  This is due to the broad authority contained in the statutes allowing Commission regulation in a manner deemed appropriate to provide fair, just and reasonable rates to customers.  Some parties prefer, however, that this authority be clarified by legislative action.  Third, as deregulation occurs, some form of consumer protection legislation or rulemaking could be considered.  At a minimum, the Commission's role as a neutral third party in resolving disputes and forging consensus between utilities and customers should be preserved.

PacifiCorp is advocating federal legislation to ensure open access for all customers nationwide by 2001.  That company proposes to work with states to establish the needed state legislative and regulatory environment.

B.Regional solutions and reciprocity.

The parties note that the Commission is monitoring, with interest, two developments affecting our region:  the FERC actions to increase competition in the electric industry and the Comprehensive Review of the Northwest Energy System.  The outcome of these proceedings may, if they haven’t already, influence Idaho electric utility regulation.  Idaho’s utilities are concerned that they may lose customers to competitors without the opportunity to acquire new customers in other areas.  This is primarily a timing issue, but at this juncture, it is unclear what Commission action may or could be taken.  Certain Idaho customers desire to obtain immediate access to other, lower cost suppliers.  Industrial customers are also concerned that they not be forced to pay electric rates that exceed those paid by their competitors in other states, jurisdictions or service territories.

C.Obligation to serve, obligation to transport, and eminent domain.

The obligation of Idaho’s regulated utilities to serve all those requesting service will, of course, vary to the extent that the operations of those utilities have been deregulated.  If retail wheeling is permitted and customers choose, for a period of time, to obtain power from other sources and then wish to return to the utility for service, a legitimate question is whether the utility who was serving that customer is obligated to serve them once again and if so, at what  rates.  New rate schedules specifying what rates or conditions would be applied in this event, might be considered.  At a minimum each distribution company must continue to have the obligation to connect all customers in its service territory to the distribution system.

Competition for customers along shared service boundaries has become more common.  Some believe that restrictions in choice for new customers may slow the evolution of competition and that utilities under the Commission’s jurisdiction should have the flexibility to compete with other electric service providers in a manner which does not disadvantage the utility’s existing customers.  Others would argue that the ESSA currently governing which utility may serve new customers, was designed to minimize the economic costs of redundant and competing distribution systems, is still valid, and should, to that extent, not be changed.

D.Stranded costs examination and potential recovery (e.g., deferred income taxes, DSM investments, above-market purchased power agreements, uneconomic generation costs, and other deferrals).

The possibility exists that if competition in power supply markets becomes widespread, some utilities may find it impossible to collect adequate revenues to recover all the costs incurred in a regulated environment.  These potentially unrecoverable costs are referred to as “stranded costs” and include costs associated with existing generation facilities that may not be recovered through the competitive market price for generation, the amount by which existing purchased power contracts exceed the competitive market price for generation, and prudently incurred regulatory assets that were intended to be collected over time.  The magnitude of any potential stranded cost liability will vary by utility.

Utilities argue that today’s stranded costs were incurred to provide high quality electric service to customers at reasonable and fairly stable rates.  If these costs met prudency tests when they were included in rate base, it is unreasonable to expect the utility to absorb them now.  Others argue that the utility was never given more than the reasonable opportunity to recover these costs and that what utilities are now asking for is a guarantee that these costs will be recovered.

If a policy to allow recovery of stranded costs is adopted by the Commission, the amount to be recovered must still be quantified.  The common definition would require that for generation assets and power purchase contracts the embedded cost be compared to the market price and the differential classified as stranded.  Unfortunately, arriving at a market price with which to compare embedded cost will not be a simple task, and not everyone agrees that market price is the appropriate measure to use.  Some would suggest that the marginal cost of new resources would be better.  There will also be discussion as to whether stranded costs are determined on an asset-by-asset basis or whether a utility's assets will be considered as a whole to determine if stranded costs exist.

Assuming stranded costs are quantified, it must then be decided how to allocate them between shareholders and customers, then among customers, some of whom may be leaving the system; and finally, how and over what period they should be collected.  One possibility put forward is to determine a reasonable sharing of stranded costs between shareholders and customers, and among customer groups, then on a transitional basis to recover them through a non-by-passable surcharge until the unamortized balance is reduced.

At least one utility has stated that many of its contracts with cogenerators or small power producers constitute stranded investments.  Another participant urged that these contracts be protected from potential legislation or regulatory intervention by FERC.

E.The relationship between existing hydro resources and existing customers within the context of relicensing.

Idaho customers, today, have low electricity rates due, in part, to an abundance of hydro-based generation.  A distinctive cost characteristic of hydro-generation is that it is most expensive in the early years of a facility’s operation and becomes relatively less expensive as the plant is depreciated.  Utility customers often feel they have a stake in these resources because they have paid for them over the years through depreciation expense included in their rates.  Some customers argue that it would be unfair to deregulate generation if it causes them to lose their perceived stake in these facilities.  Others believe that, given potential costs of relicensing that may be incurred over the next decade, it is unclear whether hydro resources will remain a benefit or become a burden.

The Commission could entertain the option of somehow preserving the costs/revenues of hydro for its Idaho customers.  Utilities argue, however, that if the Commission chooses to retain hydro-benefits or “negative stranded costs” for customers, it must also allow the utility full recovery of any stranded costs associated with other resources and purchase contracts.  Finally, if these resources ultimately prove not to be cost effective and a portion of the cost of these resources becomes stranded, the Commission would be faced with the problem of how to make its investor-owned utilities whole.

F.Public purposes (e.g., DSM, renewable resources, social programs) and alternative funding mechanisms.

The objective of meeting customer needs becomes increasingly important in competitive environments.  The installation on customers' premises of demand-side management measures (DSM), such as insulation and other energy-efficiency products that allow customers to reduce their demand for electricity, may be such a customer service with dividends of cost-effectiveness for individual customers. Although DSM has, for a number of years, been paid for by the utility, the industry has seen a trend toward DSM being “customized” for specific customer groups with these customers paying a large part of the costs because it is cost effective for them to do so.  Additionally, a utility response to a more competitive industry may include a focus on market transformation, smaller scale direct funding (so that all customers will have some access to DSM services), and a continuation of limited income programs.  (Limited income weatherization programs may continue to have merit for utility funding in a competitive environment because such programs can result in fewer delinquent accounts, disconnects, etc. and because electricity remains an essential service requiring distribution companies to provide universal access.)

Funding for these programs may be possible through a universal access charge on the distribution side which recognizes that cost-effective public interest goals may still be accomplished.  Such a charge would allow the utility’s generation to compete with third party producers without added costs not applicable to that competitor.

Renewable energy resources, such as wind and hydro generation whose common characteristic is that they rely on non-depletable or naturally-replenishable resources, may need to compete against lower cost generation.  Even over a 20-year period with assumed inflation, natural gas projects remain low cost; however, some renewables (wind, methane from landfills) may be cost-effective and utilities need to explore these options and “funding alternatives” (if there are front-loaded impacts).  Some advocate “green tariffs” which would allow customers to choose to purchase power from more expensive renewable resources that may be more costly in the short term but that they believe will be cheaper in the long run.  Others argue that to expect customers to choose to pay rates above market prices today is impractical and, therefore, won’t ensure that renewable resources are developed.

Prohibitions that limit utilities' ability to disconnect service to non-paying customers during the winter (commonly referred to as the moratorium) need to be examined.  The recognized dangers to life and property of winter disconnection should be weighed against the economic impact of policy.  While it is unlikely that all restrictions will be lifted, it may be possible to develop a more focused strategy for dealing with payment-troubled customers.

G.Utility flexibility in dealing with customers (including both price and service options).

Under traditional regulation, customers have been grouped into classes with others of similar load characteristics, and average rates have been set for the class.  Using this method, some customers pay more than the cost of serving them; others less.  Because of this, some lower-than-average cost customers will have more competitive alternatives than others.  Utilities desire to have pricing flexibility to meet these customers’ competitive alternatives.  Customers, without alternatives may benefit if such flexibility means that the utility can continue to serve customers with alternatives and collect a contribution to cover fixed system costs that would otherwise be lost if they left the system entirely.  Prices for core customers will continue to have a greater need for regulatory review and care will have to be taken to ensure that if utilities are allowed flexibility they do not misuse it to compete unfairly with other providers.

H.Price unbundling and cost assignment.

A primary reason for the current industry examination is to find ways to allow customers some choice in the source and types of electric services they buy.  Customer responsiveness may require unbundling of some services in the future.  “Unbundling” would require the identification of distinct products and services now “bundled” into electric rates.  However, an unbundled rate structure could, conceivably, include any  number of packages or an array of customer options.  In the natural gas arena unbundling has been driven by customer needs and alternatives and has seen a slow evolution on a limited basis.

Full unbundling may not be to the benefit of all customers or utilities due to complexity and lack of benefits to many customers.  However, expanded customer choice through a greater diversity of pricing options (e.g., “premium service”, standard service, interruptible service, “read your own meter rate,” etc.) may be beneficial to all concerned.  To the extent that unbundling does occur, care will have to be taken to ensure that cost-shifting and/or cross-subsidization do not occur in the process.  In Idaho, it appears that most customers are currently satisfied with existing services, but some are interested at this time in defining the various components of the services they now receive and establishing the costs to the utility of providing those services.  Customers may seek options later as technology and economics change.

In general, tariffed exit/entry fees do not appear to be customer-responsive.  Connection fees and disconnection costs may best be addressed on a contractual basis as appropriate.

I.The necessity for and use of an approved integrated resource plan (IRP) vis a vis competitive markets.

Currently, utilities submit IRPs on a biennial basis to the Commission.  The plans present what utilities forecast their future loads to be and explain with what resources they plan to meet those loads.  They have been developed with input from the public through meetings conducted by the utilities.  Increasingly, around the country, utilities are asserting that the information about their businesses that has traditionally been made available to participants in the IRP process will qualify as trade secrets in an unregulated environment and should no longer be required to be made available to others by the utility.  It is also argued that in a competitive environment, utilities must be more flexible than they currently can be under the constraints of a formal public planning process.  Others would contend that the integrated resource planning should be retained, and key characteristics clarified (e.g, flexibility as an informational tool to provide a preview of coming issues).  They also believe that all utilities have some form of long range planning, and IRP may bridge this planning with regulatory and public involvement concerns if exercised in a flexible manner.  Most companies in a competitive environment place high value in meeting with stakeholders, the expert public, and customers; utilities would continue to convene public involvement sessions but may require flexibility for need and types of meetings.

J.Service quality

Service quality as it relates primarily to distribution and customer service can be broken down into three components: reliability, provisioning (providing new service, including new construction), and accessibility and responsiveness to customers.  Some participants believe that maintaining a level of service quality consistent with customer expectations should be the cornerstone of any enterprise, regulated or not.  They cite cases showing that absent uniform industry standards and a system of accountability, service quality can deteriorate.  They believe it is imperative, therefore, that the Commission, industry and consumers jointly develop performance standards and a mechanism for assuring adherence as soon as possible.  Current levels of performance should be taken into consideration when benchmarks are established.  Once standards are set, the Commission would assume the responsibility of monitoring performance and requiring compliance.

V.SUMMARY--REGULATORY AND LEGISLATIVE ACTION ITEMS

Regardless of what action the Commission takes with respect to deregulation, there are two overriding concerns facing the Commission.  First, the Commission should seek to assure that customers continue to receive a high level of service quality and reasonable rates.  Second, availability of sound information will be vital to customers as customer choice enters the electric industry.

Recommendation No. 1:  Examine restructuring from a regional perspective.

Action contemplated--Review and report on restructuring activities in surrounding states.  Develop policies that, to the extent possible, will allow Idaho the opportunity to remain a full participant in its regional energy market.  At a minimum, policies will be reviewed from the viewpoint of not inadvertently or inappropriately interfering in the economics of this energy market that might harm the citizens of Idaho.

Primary effort--Participate in the ongoing discussions of Wyoming, Nevada, and Washington.

Completion date--A report will be available at each meeting of the Idaho Commission with a full report completed as part of the report to the legislative session for 1997.

Responsible party--IPUC Staff.

Recommendation No. 2:  Examine adoption of service quality standards.

Action contemplated--Development of existing service level benchmarks.  Any proposed change to existing regulation to be accompanied by customer service plan.

Primary effort--IPUC directed study on current customer service standards and actual results.

State legislation to clarify Commission's ability to monitor and enforce performance standards.

Recommendation No. 3:  Examine customer relations policies

Action contemplated--Revisit current policies in light of the transition to competition.

Primary effort--Collaborative effort to examine existing rules and regulations, and identify need to make modifications and/or seek legislation to clarify or strengthen consumer protection.

Recommendation No. 4:  Consider legislation for consumer protection in a deregulated environment.

Action contemplated--Develop legislative language  emphasizing the Commission's role as mediator and arbitrator of consumer-utility disputes with attendant authority to impose sanctions if necessary.  Underscore authority to set policy with respect to public safety, convenience and necessity.

Primary effort--Activity in 1997 legislative session.

Recommendation No. 5:  Seek agreement on DSM, previous commitments to

PURPA, etc.

Action contemplated--Consider alternative funding mechanisms such as system benefit charge for new programs and inclusion of costs in transition rates, as appropriate.

Primary effort-- Utility by utility analysis per Commission investigation.

Recommendation No. 6:  Examine stranded cost magnitude and treatment.

Action contemplated--Identify each utilities' exposure as distinguished from cost of service and consider experimental tariffs.

Primary effort--Utility by utility analysis per Commission investigation.

Recommendation No. 7:  Consider expansion of service options to customers.

Action contemplated--Utility examination of existing tariffs, services, and costs. Consideration of new service and pricing options.

Primary effort--Utility by utility filings for optional tariffs.

Recommendation No. 8:  Pursue pricing flexibility.

Action contemplated--Continue to recognize the balancing of customer-responsive special contracts/optional tariffs.

Primary effort--During transition period, continued attention to means to offset price increases with other alternatives (e.g., accelerated deferred investment tax credits, wholesale revenue, etc.) on a utility by utility basis or through transition rates.

Recommendation No. 9:  Explore provision of competitive service.

Action contemplated--Continue use of special contracts for large customers, and explore the use of alternative tariffs, experimental and otherwise for medium-to-small customers.  Ongoing, supportive legislation.

Primary effort--Individual utility filings; development of supporting legislation.

Recommendation No. 10:  Develop market-based mechanisms that will ensure all customers have the opportunity to participate in greater levels of competition if they so choose.

Action contemplated--Proposals will be formulated that will offer options for each customer class.

Primary effort--The residential and small-to-medium sized commercial class will have options presented to them such that they will not be denied the purported advantages of increased levels of competition.

Completion date--January 1, 1997.

Responsible party--IPUC Staff.

Recommendation No. 11:  Re-examine the Electric Supplier Stabilization Act

Action contemplated--Collaborative effort prior to seeking legislation.

Primary effort--Activity in 1997 legislative session.

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