Integrated Targeted Area Resource Planning (ITARP): A Model for Transmission and Distribution Planning in the Deregulated Utility

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Integrated Targeted Area Resource Planning (ITARP) is a comprehensive transmission and distribution (T&D) planning process designed to meet local area energy delivery needs at least-cost. ITARP accomplishes this objective by evaluating a full range of planning solution options and selecting the option or options that provide a least-cost solution with the necessary level of reliability. Under ITARP, the life-cycle costs of each option are evaluated on a present value basis, so that investments in small-scale distributed generation options and targeted energy conservation programs which defer or avoid the need for large investments in the T&D system may prove to be more cost-effective than traditional T&D planning solutions. ITARP can be applied under either a traditional industry and regulatory structure, or in a restructured environment.

INTRODUCTION

Electric utility transmission and distribution (T&D) costs comprise more than half of new utility capital investments, and T&D costs are rising faster than investment in total utility plant. The most cost-effective solution to a T&D need may be a traditional T&D project, or it may be to avoid or defer the project through small-scale distributed generation technologies (DG), targeted demand-side management programs (TDSM), or other means. Integrated Targeted Area Resource Planning (ITARP) is a planning tool that can be used to identify the best solution for meeting T&D needs. Using detailed local information, it considers all potential resources to meet identified local energy service needs at the lowest cost while taking into account environmental impact. ITARP can be applied under either a traditional industry and regulatory structure, or in a restructured environment.

The electric utility restructuring movement will in all likelihood, fundamentally alter the basic processes of utility operations and regulation. Similarly, restructuring will also change the way economic efficiency and societal objectives are considered. All of the restructuring models under consideration share the vision of an unregulated competitive generation market with the transmission and distribution systems and functions separated into transmission companies (Transcos) and distribution companies (Distcos). The Transcos and Distcos will likely be subject to continued regulatory oversight due to their intrinsically monopolistic characteristics, persistent economies of scale and retained land condemnation rights.

A primary concern is that the restructured utility functions may fail to efficiently allocate resources and invest in, or encourage investment in energy efficiency and renewable technologies. To address this concern, this paper presents the Integrated Targeted Area Resource Planning regulatory model. The objective of ITARP is to ensure that a full range of planning options are identified and equitably evaluated with respect to the full cost of the T&D function. The ITARP model consists of policy and analysis tools in a regulatory structure that ensures efficiency and conservation are given equal consideration in T&D planning.

THE BASIS FOR ITARP

T&D investment large and growing

T&D costs represent a large, and rising, fraction of electric utility capital costs:

- Currently, utilities invest over 50 percent on average of their new capital in transmission and distribution.
- Operation and maintenance (O&M) costs for T&D have increased at an average rate of 7.2 percent per year, while O&M costs for all utility functions have grown at 3.7 percent annually[1];
- The value of plant in service for T&D (nearly 30% of all plant in service) has increased an average of 5.6 percent annually. Total utility plant in service has grown at 4.5 percent annually[2];
- The value of T&D equipment in 1993 was over $23 billion, or $4.3 billion more than the value of all nuclear generating assets in the U.S.[3].

Utility T&D planners usually do not explore alternatives to conventional T&D planning options when faced with a system need. Line reconductoring, larger transformers, and line extensions are often seen as the only solutions for reinforcing or expanding transmission and distribution service.

ITARP evaluates all options

ITARP is a method by which less-costly means to providing needed services can be explored. Using ITARP, analysts can determine whether properly targeted small-scale generation, energy storage, targeted demand-side management programs, or other options could meet a transmission or distribution need less expensively. Applied singly or in combinations, alternatives identified by ITARP may be able to reduce localized energy demand and/or provide energy generation at the location where it is needed. ITARP is particularly applicable when a T&D project is driven by slow and steady peak load growth, since targeted demand-side management programs and distributed generation options lend themselves well to being added incrementally.

Trends make alternatives attractive

The changing electric utility industry has made alternatives to traditional T&D options attractive:

- The real costs of alternative—modular and renewable—generation technologies are decreasing moderately and would decrease significantly with mass production.

- Central generating plants no longer enjoy the advantages of economies of scale to the degree that they once did. Competitive concerns discourage large capital outlays and create load growth uncertainty.

- End-use control and monitoring technologies and communications devices are improving rapidly, making load control programs and rate options that could be used for peak load control more widely available.

- Utilities concerned about competition are searching for opportunities to reduce the cost of energy services to their customers. In a restructured industry, successor utilities and others such as power brokers and aggregators will seek lowest-cost options to offer potential customers. Similarly, competition will require utilities to be more responsive to customer needs. ITARP's focus on end-use requirements can be effective tool for utilities to demonstrate an increased level of customer responsiveness.

- The public vocally opposes T&D projects that they perceive as threatening their property, livelihood, or environment. Utilities may find it difficult to obtain approval for projects unless they can demonstrate that they have fairly addressed the public's concerns.

ITARP's advantages

ITARP addresses the above trends and, in doing so, offers several significant advantages over T&D planning as it is currently performed.

- ITARP may identify solutions to T&D energy delivery problems that are less costly than conventional solutions.

- ITARP-identified alternatives may defer or completely avoid the need to construct new transmission lines and distribution substations.

- The modular nature of alternatives to traditional T&D line construction means that these options can be implemented incrementally to match load growth. Small incremental investments spread out over time will often have a lower net present value than lump-sum investments as typified by traditional T&D improvements.

- Properly implemented, alternative solutions identified by ITARP may increase system reliability. Numerous smaller units are unlikely to fail simultaneously and result in impacts equaling the failure of one large unit. In addition, the distance between sources would, on average, decrease. Outages are less likely, line losses are lower, and power quality and power factor are improved.

- ITARP objectively evaluates a comprehensive set of alternatives, including renewable energy and demand-side management resources, and in a restructured industry, ITARP could be a vehicle used to ensure the continued implementation of renewable technologies and demand-side management.

- ITARP can provide a constructive forum for public involvement. By involving affected citizens in a process that addresses all alternatives, litigation may be avoided.

- Environmental impacts are taken into account in the ITARP process. Considering impacts on wetlands, endangered species, historical/archeological sites, and other impacts from the outset can help mitigate impacts and avoid litigation.

ITARP offers benefits to all stakeholders. For the public and the regulators and intervenors who represent them, ITARP offers a way to reduce costs and encourage, where cost-effective, energy sources that minimize environmental impact. For citizens whose property and livelihood may be affected by a traditional T&D option, ITARP offers an opportunity for discovering practical alternatives. For utilities operating under current regulation, or their successors in a restructured environment, ITARP may reduce or defer

T&D costs. ITARP may help shelter them from the costs of future environmental regulations by selecting options with less environmental impact. Approval to proceed with the selected option, whether it is a traditional T&D or an alternate solution, may meet with less or no resistance. In a restructured industry that includes retail competition, aggregators of power supply and suppliers of T&D services may benefit from ITARP-identified savings and efficiencies. For all stakeholders, ITARP offers an opportunity to avoid expensive litigation that may be initiated when all alternatives to a T&D project are not evaluated in a timely manner and implemented if appropriate.

ITARP: BACKGROUND and PRINCIPALS

Origins of ITARP

ITARP evolved from the Targeted Area Planning (TAP) process begun in Wisconsin in 1994. TAP itself grew out of the Distributed Utility (DU) and Distributed Resources (DR) concepts now being considered and used in a number of jurisdictions. The major difference among DU, TAP, and ITARP is the degree to which the approach provides a planning framework. All three approaches seek to identify less-costly alternatives to traditional T&D projects. While DU focuses largely on identifying the specific technologies that might provide those alternatives, TAP in Wisconsin went a step further. A collaborative developed analytical techniques for screening and analyzing proposed T&D projects, and incorporated TAP into Wisconsin's regulatory process. ITARP adopts and expands upon the techniques developed by the Wisconsin TAP collaborative, recommending their use in a proactive and comprehensive manner in the context of a given jurisdiction's regulatory structure and needs.

ITARP methods rely on the implementation of targeted DSM programs and small-scale distributed generation (DG) technologies. Applied singly or in optimal combinations, ITARP solutions can reduce localized energy demand or provide local energy generation where it is needed. ITARP's conceptual appeal is clear. Utilities today are on average investing over 50 percent of new capital in transmission and distribution. Yet these assets are poorly utilized, since they are built for infrequent, but large peak loading. Compounding the problem is that utility T&D planners do not explore alternatives to conventional T&D planning options when they are faced with a system need. Line reconductoring, larger transformers, and line extensions are often seen as the only solutions for reinforcing or expanding transmission and distribution service. The ITARP concept suggests that properly targeted generation, storage, and/or specially tailored customer efficiency programs can be used to handle these infrequent peaks, while simultaneously being dispatchable for system-wide needs as well. It should be noted that ITARP does not presuppose a particular planning outcome, or favor any particular DG technology. Instead, ITARP seeks to identify and select the best cost-effective resource or combination of resources to meet a defined need.

Principles of ITARP

Regardless of who the ITARP analyst is—a regulator in a state with a traditional, vertically integrated utility, or an aggregator seeking a market under a retail competition scenario—and regardless of the regulatory structure in which ITARP is being applied, certain fundamental principles should be kept in mind when using ITARP. They are:

Principle 1. Be inclusive. Evaluate all proposed T&D projects for the suitability of cost-effective alternatives. Better yet, consider each local area's energy service needs using ITARP prior to the time that a T&D project is proposed. Responsibility for identifying projects or needs and conducting ITARP would vary depending upon industry structure, regulatory authority, and other factors.

Principle 2. Identify transmission and distribution problems early enough to allow full consideration and analysis of alternatives. If needs are not identified early enough, it is often too late to do anything but proceed with the traditional T&D option. Early identification of options also makes the planning process more efficient by allowing the analysis to proceed in a logical sequence.

Principle 3. Use a systems-level approach. Consider both transmission and distribution projects. Although transmission system construction and modifications typically represent larger capital investments than do distribution systems on a per-project basis, annual distribution expenditures often exceed transmission outlays. Although any individual distribution project may seem insignificant in and of itself, when considered as part of the whole process, alternatives to it may present a more cost-effective solution over the planning horizon. In addition, projects that initially appear to be driven by transmission needs may be amenable to alternative solutions at the distribution level.

Principle 4. Explicitly consider environmental, land use, and other often-excluded costs and benefits in the analysis. Benefits should include synergies by means of which a resource helps to solve multiple problems. Account for all costs and benefits on a life-cycle basis. Taking costs and benefits fully into account not only results in the lowest-cost option from society's point of view, but may help to prevent expensive litigation later in the process.

Roles of the stakeholders

ITARP can satisfy and reconcile the diverse objectives of each group of stakeholders. Utilities want to minimize costs, maximize reliability and satisfy customer needs. Their successors and other entities that may arise in a restructured industry, such as power aggregators, will have an incentive to do the same. Regulators are charged with protecting the public interest, energy advocates want solutions that maximize public benefits, and citizens want energy delivered reliably, at low cost, and with minimal impact of their livelihood, environment, and property. The role of each of these groups is discussed in more detail below.

The Utility. Electric utilities, restructured or not, largely accept ITARP's fundamental premise; namely, to provide energy delivery services at the lowest cost. Conventional transmission and distribution facility construction is capital intensive, and T&D system load factors are low. Utility planners now recognize that alternative lower-cost solutions may exist that provide the required level of reliability and meet customer service needs. Furthermore, ITARP can provide utilities with a degree of protection in contested construction application cases. The magnitude and intensity of public opposition may be lessened if the utility can clearly demonstrate that all alternatives were evaluated before requesting regulatory approval to build or recover the cost of new transmission lines.

However, if ITARP is applied haphazardly or incorrectly, the utility may be doing a disservice to its shareholders, customers, and the public at large, by missing cost-saving opportunities. For utilities to successfully implement ITARP will require the cooperation of utility personnel in diverse departments that historically may have been isolated from one another. T&D, metering, billing, marketing, DSM, and planning functions will need to work together. The acceptance of a new way of conducting T&D planning will be critical.

The Regulators. Regardless of restructuring's possible outcomes, regulators will still be vested with the responsibility of safeguarding public interest. The focus of that effort will reside in regulating the transmission and distribution function for several reasons. One is that transmission and distribution systems will continue to enjoy economies of scale. It will remain more economical to have a single T&D infrastructure supporting multiple buyers and sellers, than for each market participant to construct their own energy delivery and control system. Next, is the fact that a reliable and safe T&D system is necessary to the functioning of our society. Since there will be only one system, it is the regulators responsibility to ensure that the costs borne by, and accrued to the public are equitable. Because there will be only one T&D system and because all citizens benefit from its presence, it is reasonable to assume that those utility business functions responsible for the siting and construction of transmission and distribution systems will maintain the right of eminent domain. In order to retain that right, due process for construction authorization is and will be required and regulators are a critical element of due process. If regulators are knowledgeable about ITARP practice, and if they hold the utility to ITARP's standards, public interest will continue to be protected.

The Public. Two public constituencies may play a significant role in ITARP: they are the intervenors and advocates, and citizens-at-large in neighborhoods potentially affected by a planned T&D project. The advocates' role may be critical, especially in the early stages of ITARP development and implementation. Advocates are likely to ask tough questions and attempt to ensure that all reasonable options are identified and evaluated. Advocates may also offer expertise in areas such as renewable technologies or environmental impacts.

The role of citizens in communities potentially affected by a T&D project role in several ways. As the people most affected by a proposed line, these citizens may wish to express their opinions as to the project's impact. They may be more willing to participate in load control or conservation programs if it means avoiding the construction of a line they do not want. Similarly, business and industry leaders can speak to their willingness to accommodate distributed generation facilities in or around their business locations. Also, successful implementation of DR alternatives may be enhanced if the local utility develops a good working relationship in the residential and business communities where the needs and objectives of all parties are clearly articulated and solutions are sought within a cooperative framework.

ITARP ANALYTICAL METHOD

In order for ITARP to compete with conventional T&D solutions for a particular need, it must be able to demonstrate economic and system benefits. These magnitude of the benefits will depend on a number of factors including: marginal avoided T&D costs; the costs of all viable alternatives; the timing and location of the need; the existing or required rights-of-way; the reason for the need—normal load-growth, bulk load addition, or transfer capacity increase; and the environmental impact of the planned alternative(s). It is important to remember that the value associated with each of these factors must be determined for the specific area in question, and not the system average which will usually tend to understate the potential benefits of ITARP. The basic steps in the analysis are:

1. Need Definition and Background Information

The objective of this task is to fully describe the need type and location so that the load drivers in the area can be altered or be otherwise met by distributed solutions. This is an information gathering step where the local area need or proposed T&D project is presented in terms of electrical diagrams, load duration curves and load growth forecasts for the study area and all affected transmission and distribution equipment in the area. The information is used to determine the minimum local area coincident peak load reduction necessary to defer or cancel the T&D project. Included in the area description is demographic customer information that shows the number of customers by class and standard industrial classification code (SIC), their connected load, current load management programs (interuptible rates, direct load control and DSM), and any customer-owned generation. Unique factors such as special reliability needs and existing customer-owned generation should also be identified.

Need definition will typically originate with load flow analysis of T&D system performance. Given the complexity, data intensity and cost of load flow models, the utility function charged with transmission or distribution planning will remain cognizant for this step, regardless of industry structure.

2. Resource Identification

This step identifies the technologies and costs of all feasible solutions for the targeted study area. Cost and performance data should be collected for the proposed T&D solution as well as any alternative T&D solutions[4]. Additionally, cost and performance data should be gathered for DG options which are appropriate for the study area. The magnitude of the need, its duration, and the reliability needs of the specific end-users will define which alternatives may be workable. Demand side program estimates of cost and kilowatt reduction potentials need to be developed based on the connected load information obtained in Step 1. Each targeted area will have its own unique resource characteristics which will affect the economics and behavior of a specific technologies—especially renewables. While generic national average estimates are a reasonable first order approximation, planners must seek out detailed area specific information that may identify factors like favorable wind resources, close access to biomass fuelstocks, and existing land-use patterns and zoning.

3. Analysis and Decision Making

The resource option analysis should be done on a basis that provides the necessary level of voltage support, voltage quality, and reliability. The total installed costs for each option need to calculated along with lifetime costs[5]. Present value accounting should be performed at the appropriate discount rate. Different discount rates may be required for each proposed solution to account for differing risk factors such as fuel costs and environmental regulations.

For distributed generation options, system capacity and energy benefits should be included if the DG option is dispatchable or otherwise provides system support benefits.

Cost estimates should include monetized factors for air pollutant emissions in jurisdictions where they are allowed. Other factors also need to be included in order to enable informed decision making. These include aesthetics, safety, landowner acceptance/opposition and current land use practices.

The analysis should compare system reliability and security among the alternatives, recognizing that all customers do not have the same reliability requirements. In a competitive market, energy will be a commodity and should be delivered according to the end-user's specific requirements. Residential customers for example, do not like outages but their real cost of losing power is minimal especially when compared to hi-tech manufacturing plants whose outage costs may run into millions of dollars per hour. The energy delivery business should recognize this difference and attempt to price service and allocate capital investment with consideration given to area specific or micro-reliability issues.

The economic analysis should provide the planner with a complete cost estimate of canceling the T&D project outright, as well as the cost of deferring the project for one year, five years, and ten years. By looking at multi-year deferral options, advantages may be realized that are not otherwise apparent when looking at a single point in time.

The recommended solution should be based on consideration of the economics and qualitative impacts of the alternatives that provide the necessary level of reliability and voltage quality. It should also prioritize the selection of resource options that closely follow the load distribution curves of the targeted area. Lastly, the solution should recognize the advantage of using modular technologies when and where they are needed as compared to long-term commitments to permanent conventional solutions.

ITARP SCREENING CRITERIA

Under certain conditions, it may not be possible to use ITARP to evaluate all projects or area needs in a utility's service area. If the utility is beginning to implement ITARP, regulators and the utility may want to evaluate ITARP before committing to it as a full-scale process. Similarly, if a jurisdiction has a large number of T&D projects scheduled for docketing approval, regulators may want to determine which projects are most amenable to ITARP solutions. For these situations, the ITARP Screening Criteria was developed to winnow the list of projects down to a smaller number of projects who's characteristics suggest ITARP will have a high probability of success to defer or avoid the need for new T&D facilities.

The objectives of the screening tool may be stated as follows:

(1) To identify transmission or distribution projects that may have a high ITARP potential;

(2) To identify transmission or distribution projects appropriate for detailed ITARP analysis.

(3) To provide utility planners with a project screening tool which can be used to prove that the potential for ITARP alternatives was considered, regardless of whether or not ITARP options were identified.

(4) To provide a quick, manageable, and comprehensible process to identify demand or energy needs that are suitable for ITARP alternatives.

To be effective, the screen was designed to be readily understandable by utilities, regulators and the public-at-large. It also needed to be simple and quick. If not, it may be perceived as an additional burden to planners or as a smoke-screen to hide the decision-making process.

It has been argued that certain project conditions may act as a ''fatal flaw'' for consideration of ITARP alternatives. Specifically, these are projects planned to support bulk load growth in an area, or projects designed to support bulk power transfer capability. However, bulk load growth needs if identified early enough can easily be met with distributed generation options—especially if the load is industrial or commercial. Transmission lines that are intended to support power transfers only, do not have a local area need as their driver and therefore cannot be solved by ITARP. However, the regulator should question whether or not approving a transmission line that increases the market power of the regulated company, is in the public interest.

The screening should be performed as part of a continuous evaluation rather than a series of discrete Yes/No answers. The screen will result in each project being assigned a numerical score based on the project's characteristics. The range of scores should provide the planner with sufficient resolution to identify the most ITARP-favorable projects. The screening tool asks six questions in five categories about the proposed project. Each answer is assigned a point value or score with a possible range from 1 to 3. Higher scores indicate a condition favorable to ITARP and lower scores indicate that ITARP is less viable. A project's total score is obtained by taking the simple product of questions 1 through 6. The screening questions are presented below.

Need Timing

When is the system improvement required? The timing of the system need will determine the viability of ITARP solutions. It is difficult to design, develop and implement certain ITARP options in the very near term (defined as less than two years.) Timing constraints for ITARP alternatives are primarily applicable to targeted DSM programs which typically have long-lead times. Planners must recognize that distributed generation options can be designed and installed in roughly the same time period as conventional T&D solutions. Timing horizons of two to five years are considered optimal for ITARP solutions to be developed.

- When is a system improvement needed?
  - Less than or equal to 2 years? = 1
  - More than 2 years? = 3

Need Type

Is the need for system improvement a function of load growth? If yes, what is the load growth rate? Load growth will likely be the critical factor to determine if a project is suitable for ITARP solutions. A need driven entirely by slow load growth presents the best possible situation to employ ITARP resources.

If the need is not a function of load growth e.g., reliability, security, or age & condition, then the load growth rate question is not applicable and should be left blank in the screening spreadsheet. It should be noted that age & condition by itself is an insufficient justification to exclude ITARP. In order to obtain protection from potential challenges to planning decisions, planners will have to provide additional explanation of the project's driver.

A project driven by bulk loads will probably not be ITARP amenable. Bulk loads tend to appear quickly relative to normal planning horizons, and bulk loads will typically exhibit energy and demand requirements greater than can be provided by ITARP alternatives. Bulk loads may appear as large industrial or commercial developments, or a residential subdivision. Bulk loads may also be characterized as the need to connect a new generating facility to the grid. It should be noted however that some bulk loads may be adequately served by distributed generation technologies. System planners need to keep DG opportunities in mind as they screen bulk load projects.

- Is the need for system improvement a function of load growth?

Yes	=	3
Partially	=	2
No	=	1

- What is the load growth rate?

Low	=	3
Medium	=	2
High	=	1
Bulk	=	1

Need Location

Can the area requiring improvement be easily defined by geography and/or electrical boundaries? If the boundaries of an affected area can easily be described, it may be possible to design specific targeted area programs to mitigate the need for additional capacity or energy services.

- Can the area requiring improvement be easily defined by geography and/or electrical boundaries?

Yes	=	3
Partially	=	2
No	=	1

Environmental Impact

Are there potentially significant environmental concerns in the area? This question tries to determine if there are concerns for environmental resources in the area under study: wetlands, endangered species, or protected lands, for example. This screening question is *not* intended to determine the requirements (or lack thereof) for an Environmental Impact Statement.

- Are there potentially significant environmental concerns in the area?

Yes	=	3
Unsure	=	2
No	=	1

Other Factors

Are there unique factors associated with the area needing support that increase ITARP opportunities? This question may include but is not limited to: political factors, fuel supplies, renewable resource availability, etc. This question is designed to identify any other critical issues associated with a given project that may indicate the need for ITARP analysis in spite of low scores in the other areas.
Are there unique factors associated with the area that increase opportunities for non-traditional solutions?

Yes	=	3
No	=	1

CUSTOMIZING THE ITARP PROCESS

Widely varying regulatory processes currently in existence, along with the changing nature of the utility industry, demand that ITARP be flexible and adaptable for use under differing situations. For example, regulators in a state with an integrated resource planning process may wish to incorporate ITARP into that existing process. On the other extreme, an entrepreneurial aggregator may wish to employ the ITARP process under a retail competition industry structure in order to identify and market low-cost resources to end users. The technical process described above can be used in any situation. What will differ from state to state and situation to situation is the regulatory framework into which ITARP fits.

Among the factors affecting how ITARP might work in a given jurisdiction are:

Industry structure

Is ITARP being applied to a traditional, vertically integrated electric industry, or has the jurisdiction adopted some form of industry restructuring? Does the restructuring entail wholesale or retail competition, or is it a hybrid? As is described in greater detail in *RESTRUCTURING and T&D PLANNING*, the form of the restructuring will affect how ITARP might be implemented.

Regulatory structure and requirements

Whether the industry is restructured or not, the jurisdiction's regulatory structure and requirements will affect the implementation of ITARP. Among the questions that are relevant are:

- What, if any, planning processes are already in place in the jurisdiction? What are their cycles? How are non-economic costs and benefits, such as environmental impacts, considered in the planning process? ITARP may well fit into an existing planning process.

- Does the jurisdiction require pre-approval of T&D and/or generation facilities, or is regulatory review confined to a review of prudence at the time the costs of the project are passed onto the ratepayers? If so, what are the size requirements for these projects? The answers to these questions are relevant for both identifying a place in the regulatory process where ITARP advocates may propose consideration of alternatives to traditional T&D, and for the regulatory requirements that may affect the project that is selected through the ITARP process.

- What are the requirements for environmental and siting review? What agency is responsible? Again, these answers may indicate a vehicle for implementation of ITARP, as well as affect the implementation of the selected alternative.

- Does the regulatory process include a vehicle for public participation? Does a vehicle exist for intervenor funding? Although the technical ITARP process can be conducted without public input, providing citizens with an appropriate mechanism by which they can participate in the planning of projects that may affect their livelihood, environment, or property will probably help avoid litigation in individual construction proceedings.

RESTRUCTURING and T&D PLANNING

Future structure of the electric industry

The electric utility industry in the U.S. is undergoing profound changes the outcome of which will affect how ITARP is implemented. Restructuring and deregulation initiatives are likely to result in an industry that bears little resemblance to the vertically integrated, comprehensively regulated structure that exists today. Although a number of different restructuring scenarios are currently being discussed and experimented with, they can be categorized generally as either promoting wholesale competition, both wholesale and retail competition, or ''hybrid competition,'' which is wholesale completion with a limited amount of retail competition.

Wholesale competition. Under wholesale competition, competitive (i.e., unregulated) generation companies (Gencos) would supply bulk power to the network for resale by power marketers. A pool company or independent system operator (ISO) would dispatch generation units and coordinate power flow throughout the transmission network. Transmission companies (Transcos) would build, operate and maintain the transmission network in order to transport power over long distances. Customers would have no choice of supplier. They would be served by regulated monopoly distribution companies (Distcos), which would aggregate services for all customers within their respective service area franchises. The Distcos would resemble many of today's distribution-only municipal utilities. The regulated Distcos would secure power supplies through unregulated, competitive bulk power (wholesale) markets. Gencos, Transcos, and Distcos could be either independent companies, or functionally disaggregated subsidiaries of existing utilities.

Retail competition. Under retail competition, customers would have full retail access. All customers in all customer classes could choose a supplier or ''aggregator'' from any one of the available competitive entities wishing to provide services to customers. These unregulated competitive entities could provide energy services ranging from comprehensive aggregation of services (power supply, T&D services, metering and billing, DSM) to a much narrower menu of services. Customers may also choose to secure power directly from Gencos through bilateral contracts. Other aspects of wholesale competition, described above, would accompany this retail competition.

Hybrid competition. Under hybrid competition, customers may have some degree of retail access. However, certain customers or customer classes would continue to be served by regulated, monopoly Distcos. For example, customers may be able to choose service from unregulated, competitive providers. Customers not choosing an alternative supplier would remain served by regulated, monopoly providers. An example of hybrid competition can be found in the UK, where the Distcos (''regional electricity companies'') are regulated for services they provide within their territorial franchise. However, customers can opt to receive service from other providers, which are not regulated. Other aspects of wholesale competition, described above, would accompany hybrid competition.

ITARP AND RESTRUCTURING

ITARP faces both opportunities and challenges from the countervailing forces being unleashed as a result of restructuring initiatives. In general terms, ITARP may fit well with a more competitive industry. To the degree the industry is functionally disaggregated, the focus will be sharpened on the cost of each unbundled service, such as distribution. The market orientation of a restructured industry should result in pressure to minimize costs in order to offer customers competitive rates and the best possible service to meet individual reliability and other needs. Innovation and better management will be encouraged in this new environment. The alternatives identified by ITARP may offer lower costs, better service, and innovation.

The challenges facing ITARP under restructuring vary depending whether the restructuring scenario being considered includes wholesale competition only, or both retail competition accompanied by wholesale competition. The basic challenge is that ITARP considers the benefits of alternative resources comprehensively, including generation, transmission and distribution; in a disaggregated, restructured industry, however, the costs may be higher than any single entity's benefits. It may not be in any single entity's interest to evaluate and implement alternatives on its own.

Under wholesale competition, ITARP could be implemented similarly to the way it would be implemented under traditional regulation. Under wholesale competition, power supplies would be purchased from competitive generators by distribution utilities that would continue to have monopoly status and be responsible for supplying electricity to all customers within a given service territory. These distribution utilities would continue to be held responsible, via regulation, for seeking the most cost-effective means of providing energy services to their end-use customers. Although they may or may not own generation themselves, the distribution utilities would need to possess information on the cost of power. Combined with the information they would naturally have on transmission and distribution costs, the distribution utilities would possess the information they would need to conduct analyses of whether the least-cost option for meeting a local T&D need is via new T&D facilities or alternative options.

In cases in which distributed generation or storage alternatives were more cost-effective than T&D construction, the question for ITARP under wholesale competition would be whether the distribution utility could and would construct the locally sited generation, whether partnerships between Gencos and Distcos would be formed, or whether another means of implementing the alternative would arise. If targeted demand-side programs or storage options were shown to be cost-effective than purchasing power from Gencos, the Distco should have no disincentive to implementing these options. In fact, a Distco functionally disaggregated from a traditional vertically integrated utility may have less of a disincentive toward implementing alternative options than do utilities today.

Under wholesale competition, the role of regulation is similar to that of today. The utility is responsible for producing and delivering energy to retail customers and is subject to regulated prices. The difference arises because the utility purchases power under wholesale competition from the open market rather than generating its own power. Regulators would still review the utility's actions to ensure that the supplies as delivered to the end users, were least-cost. Under wholesale competition, regulators would review purchase practices rather than the utility's own generation.

Retail competition scenarios provide greater challenges for ITARP than do wholesale competition options, but opportunities for ITARP nevertheless exist. In retail competition, all customers would choose a supplier or aggregator from any of the competing firms vying to supply end-use energy services. The comprehensive evaluation of system costs and benefits (including generation, transmission and distribution) needed for ITARP would be more difficult. Although an end-use service provider may want to offer the lowest-cost service to its customers, and the lowest-cost options may well include distributed generation, targeted demand-side management, and storage, the end-use service provider would not have the data needed to conduct an ITARP analysis. Gencos, Transcos, and Distcos may well resist sharing this information. Nor would the end-use provider necessarily have the wherewithal to implement alternatives found to be cost-effective.

Alternatives to traditional T&D may be possible even under retail restructuring, however. Aggregators may fill the niche of determining locations in which distributed generation, targeted demand-side management and storage are appropriate, and bring together the parties necessary to implement those options. They could function similarly to the entrepreneurs who coordinate large commercial construction projects today—arranging for land, permits, financing, and tenants (in the case of ITARP, the end-users.) ''Green Power'' aggregators may seek projects with minimal environmental impacts. Gencos, Transcos, Distcos, and/or end-use providers may form partnerships on their own to implement locally sited options, if by doing so they create themselves a market niche. Players who stand to benefit—for example, a Genco who by siting a plant in a location where lower T&D costs mean his power will be more competitive—would presumably be willing to share the information needed to conduct the analysis of the alternative's viability.

The viability of ITARP will also depend on the regulatory framework that is developed for the restructured industry. ITARP could be offered as a vehicle in the debate now underway as to how renewable and demand-side options will be maintained in a restructured industry. ITARP could be used to identify appropriate locations for renewables that may be required of Distcos or Gencos through ''set asides'' or portfolio standards. Similarly, targeted demand-side management programs identified through ITARP may be candidates for some of the DSM programs envisioned as resulting from applied wires charges.

There are undoubtedly many other potential applications of ITARP in a restructured industry and modified regulatory framework. Advocates can play a role in identifying these applications. For example, the Boston Edison DSM Settlement Board[6], have investigated how T&D resource planning might be included in a regulatory framework for a restructured industry in Massachusetts.[7]

Until the restructuring debate is resolved, it is impossible to accurately dovetail ITARP into a single ''best'' restructured utility model. Issues related to transmission and distribution ownership, operation and pricing will affect the ultimate form of ITARP. Additionally, the development and role of Energy Service Companies (Escos) may impact ITARP's final structure if the Esco is responsible for metering and efficiency measures. However, the principles and methods of ITARP are designed to be broad enough to adapt to changes in the marketplace, and more importantly, to be adaptable to changes in information and technology.

ITARP UTILITY EXPERIENCE

Several utilities are experimenting with the distributed utility concept and the Electric Power Research Institute (EPRI) has just published the Distributed Resources Technical Assessment Guide(TAG)[8]. The experiences have been mixed with some utilities finding cost-effective applications for targeted demand side programs while others have claimed that transmission and distribution construction is the only solution. It is of course unreasonable to expect ITARP to solve every T&D need however, a review of utility initiated distributed utility cases revealed that the metrics and procedures used to evaluate the cost-effectiveness of non-T&D solutions vary widely. Some utilities used present worth analysis while others examined only up-front costs. Also, there were several cases in which T&D system average avoided costs were used instead of area-specific avoided costs. Since area-specific costs tend to be higher than system-wide average costs, the benefits of distributed resources were underestimated.

Utility acceptance of the ITARP model's premise is encouraging, however there is a sense that a particular utility will choose to evaluate non-T&D options only when it appears to be in their best interest or where cost savings are obvious. However, without regulatory oversight, the potential for ITARP's success may be limited. Successful implementation of ITARP requires a new planning paradigm in which communication between historically diverse and isolated departments. ITARP will require cross-functional planning among all departments affected and responsible for planning. This will include personnel from transmission, distribution, DSM, marketing and finance for example, as well as non-utility personnel.

ITARP REGULATORY EXPERIENCE

The concept of Targeted Area Planning is still relatively new to many utilities and most public service commissions. Not surprisingly, the regulatory experience body of knowledge is shallow in this area. By far, the majority of ITARP activities to date have occurred at the utility level without regulatory oversight or other intervention except for the Distributed Utility Valuation (DUV) collaborative consisting of; Pacific Gas & Electric (PG&E), National Renewable Energy Lab (NREL), Electric Power Research Institute (EPRI), and Pacific Northwest Laboratory (PNL). By comparison, the Wisconsin Targeted Area Planning Collaborative is the only endeavor to incorporate ITARP into its regulatory environment. No other state has made as significant a commitment to define the requirements of ITARP, and reconcile the diverse objectives of the affected parties; regulators, utilities, the public.

We have found that other regulatory jurisdictions have advocated or ordered elements of ITARP to be included as part of other (non-ITARP) regulatory processes. The New Mexico Public Service Commission expressed a preference for distributed generation over line extensions under certain conditions[9]. In Oregon, commission staff opined that distributed generation should be considered during the utilities least-cost plan development[10]. The Connecticut Commission, under its retail wheeling investigation, acknowledged the potential benefits of distributed generation[11]. In Wisconsin Power and Light's (WPL) 1993 rate case, the Commission ordered WPL to begin collecting and analyzing area-specific data as the basis to identify ITARP alternatives[12]. Finally, in New England, Massachusetts Electric has agreed to undertake a pilot study on achieving energy savings through targeted demand-side management and distribution of new generation equipment[13].

CONCLUSIONS

In summary, ITARP is economically attractive, technically feasible, and it provides economic benefits substantial enough to warrant reorganizing utility T&D planning and operations. It is too early to estimate the savings attributable to ITARP, but it may provide an appropriate structure in which to maximize economic and resource efficiency for the transmission and distribution functions. ITARP can offer several significant advantages over T&D planning as it is currently performed. First, ITARP may provide solutions to T&D energy delivery problems that are lower-cost than conventional solutions. Second, ITARP may defer or completely avoid the need to construct new transmission lines and distribution substations. Third, properly implemented ITARP solutions may increase system reliability. Fourth, ITARP solicits public involvement in T&D decision making. Fifth, ITARP provides a level playing field for the evaluation of renewable energy and energy efficiency and conservation resources. And finally, ITARP seeks to minimize the environmental impact of T&D energy delivery and service systems.

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ENDNOTES

1. Financial Statistics of Major U.S. Publicly Owned Electric Utilities 1993, Table 8. Department of Energy/ Information Administration, Washington, DC. 1995

2. Financial Statistics of Major U.S. Publicly Owned Electric Utilities 1993, Table 9. Department of Energy/ Information Administration, Washington, DC. 1995.

3. Ibid.

4. Alternatives to conventional T&D solutions include capacitor banks, power factor correction, conservation voltage reduction and high-efficiency transformer installation.

5. Lifetime costs include fuel, operation and maintenance costs.

6. A collaborative consisting of the Boston Edison Company, Massachusetts Office of the Attorney General, the Massachusetts Division of Energy Resources, and MASSPIRG.

7. See *An Incentive Regulatory Framework to Encourage Cost-Effectiveness Investment in Transmission and Distribution System Resources in a Restructured Electric Utility Industry in Massachusetts*, by La Capra Associates, September 28, 1995.

8. TAG Technical Assessment Guide Volume 5: Distributed Resources 1995. TR-105124 Electric Power Research Institute, Palo Alto, CA. May 1995.

9. New Mexico Public Service Commission Case No. 2476, Rule 420.10. March 29, 1993.

10. Oregon Public Utility Commission (OPUC), UM 550 Order No. 94-727, May 3, 1994.

11. Connecticut Department of Public Utility Control, Re: Investigation into Retail Electric Transmission Service, Docket No. 93-09-29, September 9, 1994.

12. Public Service Commission of Wisconsin (PSCW), Application of Wisconsin Power and Light Company, as an Electric, Water and Natural Gas Public Utility to Increase Electric, Water and Natural Gas Rates. Docket 6680-UR-108, September 30, 1993.

13. Massachusetts Department of Public Utilities (DPU), New England Electric System (NEES) 1994–2008 Integrated Resource Plan, Docket DPU-94-112.