Performance Metrics for Market Transformation Programs: Incentivizing Progress Without Strangling Creativity

Steven Nadel, ACEEE
Dave Hewitt, Northeast Energy Efficiency Partnerships
Noah Horowitz, Natural Resources Defense Council
Lauren Casentini, Pacific Gas & Electric Company[1]
Ben Bronfman, Northwest Energy Efficiency Alliance

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1001 Connecticut Avenue, NW, Suite 801, Washington, DC 20036
(202) 429-8873 phone, (202) 429-2248 fax, http://www.aceee.org
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[1] She has recently left PG&E and now works for Four Winds Alliance, Half Moon Bay, California.

ABSTRACT

For the past decade, many state utility commissions have provided financial incentives to utilities for the successful implementation of demand-side management (DSM) programs. With the growing emphasis on the market transformation approach to DSM, regulatory incentive structures also need to evolve. This report discusses strategies for developing and configuring these incentives, drawing on experiences in three regions — New England (particularly Massachusetts), California, and the Pacific Northwest. As a result of this review, we reach the following tentative conclusions: (1) incentives are useful in states where utilities are the prime administrators of market transformation programs; (2) incentives are complex and must be developed with care; (3) increased emphasis should be placed on market effect metrics; (4) good data and market/evaluation research are an important foundation for incentives; (5) incentive metrics are often best set through negotiation, but parties need to have adequate time and flexibility; (6) a modest level of incentives appears to be acceptable to a wide range of parties in the regulatory process; and (7) current incentive approaches have difficulty addressing the dynamic nature of the markets they are trying to change, and as a result, there is a need to experiment with modifications to current incentive mechanisms.

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INTRODUCTION

This report represents a joint effort by a diverse group of participants active in planning, implementing, and evaluating public benefit energy efficiency programs and policies in California, New England, and the Pacific Northwest. We focus in this report on programs that seek to reduce market barriers and permanently transform markets for energy-efficient goods and services so that these goods and services become normal market practice in the future. In some regions, these programs are administered by distribution utilities; in other regions by non-profit and public sector organizations. Regardless of the program administrator, in order for programs to succeed, there is a need for program implementers and contractors to be rewarded in some fashion when they do a good job. For non-profit administrators, helping the public and receiving continued funding may be reward enough. But for private administrators, financial incentives are the key reward. We discuss strategies for developing and configuring these incentives, drawing on experiences in the three regions. We particularly focus on Massachusetts and California, as these are the states where regulatory incentives for market transformation are most advanced.[2] The Northwest is included to a lesser extent because even though performance incentives are not used in the Northwest, experience there with market transformation metrics provides some useful insights into how performance incentives can most usefully be structured. Our intent is to offer insights to program implementers and overseers on how to best structure these incentives to improve chances of program success. While some of our insights are region specific, most are generic and apply to all regions, be they the three focused upon here or other regions considering how best to structure performance incentives.

DSM PERFORMANCE INCENTIVES — A BRIEF HISTORY

Many utilities have offered programs to help their customers reduce energy use since the 1970s and 1980s. By the late 1980s, as programs grew in size and scope, it became clear that given the way utilities are structured and regulated in the United States, most utilities have little incentive to do a good job convincing customers to use less of their product. Under traditional regulation, as sales go down, profits also tend to go down, and visa versa (Moskovitz 1989). Two primary mechanisms lead to this result.

1. Utility revenues are based on volumetric (kilowatt-hour [kWh]) charges, while remaining costs (non-fuel costs) are more fixed than variable. As a result, utilities have an incentive to increase sales, since revenues increase more than costs.

2. Fuel adjustment clauses insulate utility profits from high operating costs since changes in fuel costs (and in some states changes in other operating costs) are passed directly on to consumers, leaving much of the revenue associated with sales as profit.

[2] In addition to these two states, New Jersey and Vermont have recently adopted performance incentives for market transformation programs and Connecticut is in the process of updating the structure of their performance incentives.

To address this problem, a number of state utility commissions and their regulated utilities began developing schemes to *decouple* profits from sales (so that utilities would be at least neutral as to future sales levels) and to offer positive incentives for doing a good job implementing energy efficiency and other demand-side management programs (i.e., programs designed to reduce the demand for energy on the customer side of the meter). As John Rowe, (then Chief Executive Officer of New England Electric Systems) noted, if policymakers want utilities to successfully implement DSM programs, then regulators need to offer financial incentives "so the rat can smell the cheese" and be motivated to act (Rowe 1989).

At that time, a number of different performance incentive schemes were developed, with the most common being to reward the utility with an incentive based on a small percentage of the net societal benefits achieved by the programs they implement (Nadel, Reid, and Wolcott 1992). Under the net benefit scheme, program evaluators determine program energy savings, financial benefits, and program costs, and based on these figures, estimate the net benefits resulting from programs over the lifetime of the measures installed. The utility and its stockholders then receive a performance incentive equal to a specified percentage of these net benefits (typically 10 percent or more), leaving the balance of net benefits to customers.

For example, in California, performance incentives began in 1990. The initial earnings mechanism allowed utility shareholders to earn 30 percent of every dollar of benefit and the ratepayers received the benefit of the remaining 70 percent. The return to utility shareholders was determined through the completion of measurement studies and the earnings were paid out over time. In Massachusetts, performance incentives also began in 1990 and used a share of net benefit approach similar to California's, although the utility share of net benefits was somewhat lower. In California, incentive payments to utilities typically totaled in the neighborhood of $30 million annually in the early 1990s. In Massachusetts, utility incentive payments typically averaged on the order of $10 million annually (Eto, Destribats, and Schultz 1992). In total, as of November1991, incentive mechanisms were approved by utility commissions in 21 states (Reid 1992).[3]

Evaluations of these performance incentives found that they were having the desired effects. For example, a 1991 study of incentives in nine states found that utilities with incentives increased their DSM spending and savings by more than nearby utilities without incentives. In most cases, the differences were statistically significant (Nadel and Jordan 1992).

[3] In the Pacific Northwest, most of the electricity is provided by public utilities and investor-owned utilities have not asked for shareholder incentives (beyond cost recovery).

RESTRUCTURING AND MARKET TRANSFORMATION PROGRAMS: THE NEED FOR NEW INCENTIVE PARADIGMS

In the mid-1990s, two trends began that have profoundly influenced utility DSM programs — utility restructuring and the introduction of the market transformation paradigm to program design. Utility restructuring began in 1994 with the publication of the "Blue Book" in California, which outlined the rationale for restructuring California's electricity industry. Since then, restructuring legislation or regulatory orders have been enacted in 23 states, including Rhode Island (in 1996), California (in 1996), Connecticut (in 1998), Montana (in 1997), Massachusetts (in 1997), and Oregon (in 1999). Details of restructuring vary from state to state, but in most states a regulated monopoly company provides distribution service while customers are free to choose from an array of generation suppliers. Under restructuring in most states, energy efficiency and other public benefit programs (programs traditionally funded through rates and which provide important benefits to the public including programs to promote energy efficiency or provide special services to low-income households) are funded by a small charge on distribution service. In most states, public benefit programs are administered by distribution utilities with regulatory oversight from utility commissions and other regulatory bodies (e.g., the California Board for Energy Efficiency [CBEE] that was established as part of California's restructuring legislation). However, in Vermont, a "conservation utility" is being set up to administer public benefit programs; in Oregon, the Public Service Commission will play a major role in administering public benefit monies; and in California, options are under consideration to switch administration to either a state-agency or a non-profit organization.

With restructuring, most of the incentives for utilities (both generation and distribution utilities) to sell more power remain in place, so providing incentives for good management of programs remains very important. In fact, in many states with restructuring, disincentives to energy efficiency actually increase — for example, price-cap regulation as is being adopted in many states tends to encourage cost-cutting (including energy efficiency budgets) and load building (Moskovitz 2000).

The move towards market transformation programs also gained traction in the mid-1990s. In the 1980s and early 1990s, the dominant DSM paradigm was *resource acquisition*. Under this paradigm, utilities sought to maximize the acquisition of cost-effective energy savings in order to reduce the need for acquiring new generation resources. Resource acquisition programs tended to emphasize the use of rebates and direct installation of energy-saving measures in individual homes and commercial/industrial facilities (utility contractors would install measures in customer facilities). These programs were effective techniques for achieving energy savings, but were also commonly costly (although still cost-effective under the avoided generation costs prevalent at the time).

Under restructuring, some (but not all) of the rationale for resource acquisition disappeared; with restructuring, provision of new generation resources is left to the market, and there is less need for regulatory intervention since ratepayers are no longer required to pay for new power plants regardless of whether the plant is used or not. Furthermore, with the competition brought about by restructuring, as well as the availability of new generation technologies, the cost of power from new power plants has plummeted, reducing (but far from eliminating) the benefits achieved from energy efficiency programs.

The market transformation paradigm offers an alternative approach that (in a successful program) better leverages the activities of the market to achieve large energy savings at costs below current avoided costs. Under the market transformation paradigm, the focus is on market barriers and taking steps to permanently reduce or overcome these barriers so that over time efficient goods and services become the norm, with no or reduced need for continued market intervention. There are many examples of successful market transformation programs that have achieved very large energy savings at costs of around $.01/kWh or less (Nadel and Latham 1998; Suozzo and Thorne 1999). Given these successes, many state legislatures and utility commissions have embraced the market transformation paradigm.[4] For example, the California Public Utility Commission has stated that:

> Our focus for energy efficiency programs has changed from trying to influence utility decision-makers, as monopoly providers of generation services, to trying to transform the market so that individual customers and suppliers in the future, competitive generation market will be making rational energy choices (CPUC 1997).

And restructuring legislation in Connecticut specifically establishes a mechanism for developing and funding "cost-effective energy conservation programs and market transformation initiatives" (Connecticut Legislature 1998).

In the Pacific Northwest, the four regional governors appointed a Steering Committee to conduct a comprehensive review of the Northwest Energy System and make recommendations on restructuring issues. The Committee report "calls for the region's retail distribution utilities to mount a coordinated effort to transform markets for efficient technologies and practices" and further notes that "[b]ecause markets invariably cut across utility and jurisdictional boundaries, it makes sense to pursue these efforts regionally" (Steering Committee 1996).

Following this report, the region's utilities and policymakers formed a regional non-profit organization, the Northwest Energy Efficiency Alliance (NW Alliance), with the mission of

[4] While the market transformation paradigm has many advantages, the market transformation approach is not appropriate for all markets, measures and policy needs — there are still appropriate applications for the resource acquisition paradigm. Furthermore, the two paradigms are not mutually exclusive — many resource acquisition programs do achieve long-term market effects (Peters et al. 1998) and market transformation programs may employ rebates or even direct installation as part of a multi-pronged approach to overcome market barriers.

encouraging the use of energy-efficient technologies and practices through the method of market transformation. The Alliance was chartered in 1996, with a three-year budget of $65.5 million, made up of contributions from the region's investor-owned and public utilities. An additional five-year capital infusion of $100 million has recently been committed. The Alliance's region comprises the states of Oregon, Washington, Idaho, and Montana. The Board of Directors is composed of representatives of investor-owned utilities, public utilities (including the Bonneville Power Administration), and public interest groups. In addition, representatives of the four state utility commissions are non-voting members who participate in all Board activities. In the Northwest, programs are implemented by a variety of program administrators, under contract to the NW Alliance.

Building on these regional developments, restructuring legislation in both Montana and Oregon specifically references market transformation. For example, the Oregon legislation establishes public purpose expenditures to fund "new cost-effective local conservation, new market transformation efforts, the above-market costs of new renewable energy resources and new low-income weatherization" (Oregon Legislature 1999). The Montana legislation states that "[t]he public interest requires the continued protection of consumers through . . . continued funding for public purpose programs for . . . market transformation . . ." (Montana Legislature 1997).

In California and New England, primary responsibility for program implementation now rests with the distribution utilities. However, in both regions, coordination across utility service-area boundaries is increasing. In New England, cooperation and coordination are primarily fostered by Northeast Energy Efficiency Partnerships (NEEP), a non-profit organization that works with utilities and other program implementers to develop common programs that can be implemented across utility-area and state boundaries. Typically, programs are designed by a working group of utilities and other program administrators, a contractor is hired to administer the program region-wide, and individual utilities contribute to program funding based on the number of customers served or kWh sales. (The Northeast model differs from the Northwest model in that budget and decisionmaking authority ultimately rests with the utilities in the Northeast, while in the Northwest, this authority ultimately rests with the NW Alliance Board of Directors.)

In California, several state-wide programs are now in operation in the residential and non-residential program areas. These programs share a common program design for all the investor-owned utilities. In some cases, the utilities hire a state-wide implementation firm managed by a committee and in other cases each utility hires its own implementation firm for its service territory.

Under the market transformation paradigm, the emphasis is no longer on maximizing the number of measures installed in the short term, but instead is on making demonstrable progress in addressing and overcoming specific market barriers. In fact, in the early years of a market transformation initiative, the number of measures that are actually installed may be scant, while instead the emphasis may be on better training service providers and increasing availability and stocking of more efficient equipment.

With the change in emphasis, performance incentives also need to change. Since market transformation initiatives do not focus primarily on short-term energy savings, incentive metrics based on energy savings are not appropriate. Instead, market transformation program evaluators focus on *market progress indicators* such as the number of trained service providers; changes in awareness of and attitudes about targeted measures; and changes in local stocking, prices, and market share of targeted equipment and services. As a result of this emphasis, in both New England and the Northwest, evaluation reports are now generally referred to as "Market Progress Evaluations." Performance metrics for market transformation programs need to move towards a similar market-focused approach. Furthermore, with the trend towards more regional cooperation on program offerings, there is a need for incentives to combine an appropriate balance of regional and utility-specific milestones.

In the following sections, initial experiences with performance incentives for market transformation programs are discussed.

ESTABLISHING METRICS

In New England and California, incentive metrics are primarily set through a negotiation process involving utilities, regulators, and/or non-utility intervenors (the parties vary somewhat from state to state). In the Pacific Northwest, metrics are proposed by NW Alliance staff and adopted by the Board as part of the program approval process. In the following sections, we discuss the metric-setting process separately for Massachusetts,[5] California, and the NW Alliance.

Massachusetts

The Massachusetts restructuring act, with its energy efficiency wires charge, passed in the late fall of 1997. Under the act, utilities are all required to submit five-year energy efficiency plans. This effort began even earlier than legislative passage, as some utilities were developing their energy efficiency plans in conjunction with their restructuring plans, for which they were trying to negotiate global settlements with the various stakeholders. Some utilities were actively engaged with NEEP in discussing market transformation plans. As preparation of the energy efficiency plans began, the parties questioned how to best propose financial incentives for encouraging the utilities to support the nascent market transformation efforts that NEEP had initiated.

[5] We focus on Massachusetts because incentives are more advanced in this state than in other states in the Northeast.

As financial incentives for utilities were considered, it became clear that generally kWh savings weren't the correct "metric" for market transformation activities. Thus began a protracted set of meetings among utility staff, non-utility party (NUP) consultants, and several NUP principals. The meetings consisted in part of getting all on the same page about what market transformation was, how one might ideally measure success, the realities of lack of good baselines for most markets, and the need for market transformation plans. Issues included whether incentives should be paid for anything other than measurable savings, whether there should be a shorter or longer list of performance metrics, and whether the metrics should be utility specific or similar statewide. The goal of these multi-utility/NUP meetings was to establish common metrics for the utilities since the state utility commission was encouraging the state's utilities to cooperate on regional market transformation initiatives. Due to the difficulties of reaching agreement on these many issues, it took nearly six months to resolve 1998 metrics, with negotiations continuing well into the program year.

The negotiated resolution on 1998 metrics ultimately included many compromises. Most of the market transformation metrics in the first year were related either to providing a given number of rebates, or to accomplishing a specific activity. Utilities and NUPs were reluctant to set metrics based on market share since in many cases there was insufficient data to determine the overall size of the specific market. Many of the rebate-based incentives were scaled to performance, with half of the incentive amount available upon distributing half of the rebates, and the full incentive available at 85 percent of goal (assuming that some variability in accomplishing goals was beyond the control of the utilities). Examples of metrics based on the accomplishment of specific activities included development of a regional market transformation plan for residential appliances, the performance of a specified number of training sessions (for a compressed air program), and development of market progress reports for some other program areas.

Development of the metrics for the 1999 program year came with several advantages — the regional initiatives had been active for a longer time and everyone (utility staff, consultants, and NUPs) had real world practical experience with them. The utilities had a year of working with the 1998 metrics and understood better how they resonated with upper management and how well (or not) they could be implemented. At the same time, the utilities still tended to look at the initiatives, their roles with them, and the metrics as individual utility oriented, focusing on what they each could do. The NUP consultants, on the other hand, began their analysis, planning, and proposals with a focus on the larger picture — the regional effort itself — and worked backwards to determine how much could be incented as multi-utility activity rather than individual utility metrics. There were differing perspectives and interests that led to a protracted process lasting nearly six months and extending into the program year. In the end, the overall content did reflect a desire to establish metrics for the development of market transformation plans, progress reports, and multi-utility targets. There were also individual utility targets related to the regional initiatives (e.g., lighting).

Sample metrics for 1998 and 1999 are illustrated in Table 1.

Table 1. Summary of Clothes Washer Metrics Used in Three Regions in 1998-2000.

	California (PG&E)	Massachusetts (WMECo)	Northwest (NW Alliance)
Studies			
1998	Survey of participating customers (16%)	Plan and complete joint baseline study (33%);	
1999	Estimate baseline market share by 7/1/99*	Plan and complete 3rd party evaluation report (33%); Complete draft market transformation plan by 9/99 (33%)	
2000	None	None	
Program Activity			
1998	Implement program within 90 days of approval; Pay 5,000-18,000 rebates (84%)	Finalize and implement program, provide at least 350 rebates (67%)	
1999	Pay at least 2,000 rebates/month for 6 months*	Provide 750-1,075 rebates (33%)	
2000	None	None	
Market Share			
1998	None	Double market share relative to baseline (alternate to achieving rebate target)	
1999	None	Achieve and document a 15% market share for ENERGY STAR® washers (alternate to achieving rebate target)	
2000 (pro-posed)	Achieve a 16% market share for ENERGY STAR washers (100%)**	Achieve and document a 20% market for ENERGY STAR washers (50%); Increase to 16% the percentage of non-participants who have heard of the ENERGY STAR program and can accurately describe it (50%)	

	California (PG&E)	Massachusetts (WMECo)	Northwest (NW Alliance)
Other (same metrics 1998-2000)			
	None	None	Increase number of qualifying models; Expanded consumer awareness & acceptance; ENERGY STAR adopts NW Alliance efficiency thresholds; National efficiency levels set at levels comparable to NW Alliance program levels.

Note: Percents are percent of maximum incentive for clothes washers devoted to each metric in each year (i.e., if the maximum clothes washer incentive is $500,000 and half of this is devoted to a single metric, then for that metric the figure "50 percent" will be shown.

* PG&E's clothes washer incentive for 1999 depended on achieving both milestones. If only one milestone was achieved, no incentive would be earned.

** While this is the only clothes washer-specific milestone proposed for 2000, PG&E proposed several global appliance milestones that will effect washers such as a milestone relating to the number of participating retailers and the number of appliance salespersons trained.

California

In California, the incentive-setting process was led by CBEE over the past several years (the process will change in the future as CBEE was abolished in March 2000, with the California Public Utility Commission [CPUC] assuming CBEE's former duties). The process began when CBEE reserved a percentage of total program costs for potential utility earnings, also referred to as incentives. While incentive levels varied slightly by utility, in 1998 and 1999 PG&E's incentive level was 12 percent. A set of earnings milestones (California uses the term *milestone* rather than *metric*) were then negotiated between the CBEE (with assistance from its technical consultants) and each utility. Simply stated, the more milestones a utility achieved, the more it earned.

The CBEE established a sub-committee to work with utilities in developing and negotiating the performance incentive metrics. Each California utility negotiated its own milestones and earnings incentives separately with the CBEE, so there is some variation in incentives from utility to utility. The utilities propose an initial mix of performance incentive metrics based on some broad guidelines by the CBEE, followed by a series of negotiation meetings. Like any negotiation, the stakeholders involved have different goals and perspectives. The regulators' goal is to achieve maximum sustainable market movement at minimum cost to ratepayers. Unfortunately, the CBEE and its consultants were disadvantaged in that they often did not have the market intelligence needed to accurately assess what is achievable. The utilities need to negotiate incentives that will ensure a reasonable level of earnings to justify the additional risks incurred by administering the programs. Therefore, tying a large portion of incentives to market effects that may be totally independent of their performance as administrators does not sit well with utility management.

In some cases, the milestones were based simply on successful program management and in other cases WEre directly related to specific market effects. While several members of the CBEE prefered a shift towards market effects type milestones, this has proven very difficult and contentious. The initial set of milestones negotiated in 1998 focused primarily on successful program management and deployment. In 1999, a shift was made to four specific types of milestones that distinguished activities between program roll-out, program activity, market effects, and aggressive implementation.

Below is a description of the milestone types used in 1999. The first three could be classified more as managerial milestones while the last one is truly market effects based. These different types of milestones can be viewed as a continuum from least risky and a weaker indicator of actual market transformation to more risky and a stronger indicator of market transformation.

- *Base/program roll-out milestone* — This type of milestone is given for just getting a program started and is the least aggressive or risky of the four types of milestones. The program administrators and implementers have a great deal of control over the outcome. This type of metric is most often used when a new program is first being launched. An example of a base metric is the release of a third-party initiative request for proposal (RFP) targeted toward small and medium business programs by a certain date.

- *Program activity milestone* — This set of milestones is for achieving a specific program-related task and doing it well. An example is to achieve a 25 percent increase in the number of heating, ventilating, and air conditoning (HVAC) contractors that completed required training in the whole-system approach. This is somewhat more aggressive than a plain program roll-out metric that might reward offering the training, regardless of the number of attendees. A more aggressive milestone around this topic would include an adder— and have at least five contractors incorporate the specifications into their projects. This adder is really a market effect (see fourth milestone type below) and represents some level of actual market adoption of the more energy-efficient practice.

- *Aggressive implementation milestone* — This measure is based on spending the budget for a particular program and is primarily used for the Standard Performance Contract programs. It is intended to incent utilities to keep a program moving beyond simple program roll-out. The down side of this type of incentive is it may result in money being spent, even when it is not the most effective use of such funds.

- *Market effects milestone* — While this type of measurement is the most desired in terms of confirming progress toward the program's market transformation goals, it is also extremely complex to project, measure, and tie earnings to. An example of a market effect milestone is to increase retail sales of ENERGY STAR-qualifying clothes washers to 15 percent of total clothes washer sales in the PG&E service territory.

Northwest

In the Northwest, metrics serve a different purpose than in the other regions. Since programs are administered by a non-profit organization, metrics are not used to financially reward the program administrator. Instead, metrics are used for two decisions: whether or not to continue a program and whether the program is cost-effective.

Two types of metrics are employed: "widget counting," and long-term market transformation criteria to judge the effect of programs at transforming individual markets. To date, while program-level decisions have been made using the market transformation criteria, cost-effectiveness is measured almost exclusively through the market penetration of measures and their quantifiable non-energy benefits.

By and large, metrics for residential programs are in the market share/market penetration realm. However, metrics for these programs also include cost reduction, market reach, and other key market indicators. Commercial programs generally have metrics associated with program accomplishments (milestones), including progress toward financial self sufficiency (sustainability) and consumer participation (reach), among other key market indicators. Metrics for industrial programs are combinations of the above. Several ventures are promoting new technologies (e.g., bio-waste digesters and magnetic-based variable speed drives) while others are developing new businesses to realize efficiency improvements in compressed air and HVAC systems, using new business concepts but widely available efficient equipment.

Alliance Staff propose metrics to the Board on a program-by-program basis. Program implementers (contractors) also have input to the metric-setting and measurement process. The Alliance uses the term "indicators of progress," whic include a range of cost-effectiveness input variables and more qualitative indicators of market progress. These qualitative indicators may include consumer knowledge, venture self-sufficiency, regional implementation, increases in number of manufacturers, or what California calls program roll-out or program activity milestones (see discussion above). The progress indicators for each program are published on the Alliance's website. Market Progress Evaluation Reports must address the indicators. If changes in indicators are recommended by the evaluation contractor, Alliance staff is required to address the recommendations in written form. Disposition of the recommendations is documented in subsequent Market Progress Evaluation Reports. A separate chapter reviewing cost-effective input variables and baseline assumptions is also required.

Metrics for a representative program are summarized in Table 1.

RESULTS TO DATE

In Massachusetts, the metrics ended up being very strong drivers of utility actions for 1998 and 1999, with attendant positive and negative effects. On the positive side, specific actions that had incentives associated with them, such as producing market progress reports and long-term market transformation plans, were given high priority and largely accomplished in a timely manner. In the past, some related activities that were included in settlements with utilities, such as conducting market research, were sometimes not given sufficient priority and not accomplished.

On the negative side there were two noticeable effects. First, if a specific activity did not have incentives associated with it, it often received little notice. It should be understood that there were some considerable mitigating circumstances from a utility perspective, including a shortened program year (after the metrics were finally resolved), a variety of new activities that consumed staff time, and some major structural changes, such as proposed mergers. As an example, evaluation or market research for programs with no metrics for evaluations wasnot scheduled in 1999.

A second negative effect was that some utilities pursued achieving rebate activity goals to the exclusion of other program elements that were equally meaningful from a market transformation perspective. In one case, rebates for residential lighting products were kept at (relatively) high levels even after the product cost dropped, and special events were used to promote the low cost products while normal retail development was largely ignored.

Overall, in 1998 and 1999, utilities tended to earn the majority of the available incentive pool but not the entire pool. For example, in 1999, Western Massachusetts Electric Company (WMECo) earned 93 percent of its maximum performance incentive for regional market transformation programs (in addition, the utility continues to receive incentives for kWh savings from more traditional DSM programs). While most metrics were achieved, they fell short in two programs due to such factors as lower housing starts than expected and difficulty achieving desired participation levels in markets for several measures.

In California, each utility has its own set of incentive milestones. In the discussion below we use PG&E to illustrate how incentives have worked. Of the total potential utility earnings in program year 1998, PG&E claimed more than 95 percent of the total potential incentive earnings. In a few cases, PG&E met part of its target and only qualified for the lower tier payment. For example, for residential efficient lighting fixtures, PG&E's milestone had three tiers for documented shipments to retailers. The tiers were:

Shipments	Incentive
60,000 - 125,000	$178,000
125,001 - 190,000	$214,000
>190,000	$280,000

By only meeting the first tier, PG&E is only eligible to earn $178,000, which is $102,000 less than they could have potentially earned had they met the top-tier target. This is a good example of a milestone that somewhat balances the utility's risk. A simple all-or-none type milestone might have resulted in PG&E not having earned anything on this milestone, a much less desirable situation for the utility and one which did not give them "partial credit" for the success it did attain in an immature market.

It should also be pointed out that although the milestones and related incentive levels were agreed to by the CPUC at the beginning of 1998, utilities are still facing opposition in the current regulatory proceeding as they try to collect these earnings. Several stakeholders who did not fully support the milestones when they were set are now trying to argue that the utilities did not meet the milestones. Arguments, both semantic and substantive, over verification methods and market baselines are also likely to occur. This highlights the importance of clear and well-defined milestones and verification processes.

In 1999, PG&E claimed 89 percent of the total potential incentives earnings. The incentives that could not be claimed were due to the spending milestones — for many programs, including several major programs, participation rates were not high enough to use the full program budget. More specifically, the following observations can be made relative to PG&E and other utilities' success/failure in meeting the milestones and the challenges in performing the required studies.

1. The milestones, especially the roll-out and program activity type milestones, were successful in keeping the utilities and their contract implementers focused. For example, the utilities were successful in meeting two roll-out milestones that resulted in the release of a statewide appliance and lighting RFP and the successful execution of a contract with a single statewide implementor.

2. Better coordination is needed among the CBEE technical consultants, utility measurement and evaluation staff and their evaluation contractors, and the utility program managers and their implementation contractors. The evaluation studies are critical to setting baselines and tracking market progress yet the program planning and implementation cycle has been somewhat disconnected from the program evaluation process. The planning of statewide measurement studies has been conducted primarily by CBEE's technical consultants in coordination with utility measurement and evaluation staff. An integrated approach between measurement study planning and program planning is required to properly document market movement associated with milestones.

3. Aggressive spending milestones that are intended to incent utility administrators to spend a large portion of the program budget are dependent upon market response to the program. In 1999, utilities were asked by stakeholders to launch new, complex programs (such as the Standard Performance Contract Program and the Residential Contractor Program), which take time to build momentum in the marketplace. Utilities with large budgets such as PG&E

were not able to meet these milestones in 1999 due to program planning and approval delays, inadequate time to build program momentum, and imbalances between program budgets and reasonable program participation expectations.

In the Northwest, the focus on the market transformation "story" has allowed Alliance projects to evolve over time without having to demonstrate immediate energy efficiency impacts. Several programs have 3-5 year time horizons where direct impacts are not expected. Still, monitoring of market transformation metrics has contributed to several decisions to cancel or modify programs. For example, a motor rebate program was cancelled when the evaluation showed that the market structure had changed so that the target market actors (distributors) no longer represented an effective leverage point. Likewise, the Super Good Cents Manufactured Housing program had significant changes in design due to consolidation and vertical integration of the manufactured housing market. Additionally, the target penetration goal changed from an absolute market share goal to a percentage over current trends. The ENERGY STAR Windows program is an example of the evaluation confirming a significant market penetration (in excess of 50 percent). Since no incentives are paid to consumers, and the window manufacturers are contributing in-kind advertising dollars, this market is assumed to be transformed (sustainable without Alliance funding). Alliance funding will end at the end of the next building season.

In the future, as programs mature and start achieving significant market penetration, "widget counting" and cost-effectiveness will become more important. In the interim, demonstrating that the program is developing along an explicit scenario gives assurance to the funders that savings will eventually occur. Proximate indicators of program progress (e.g., business established, competitors arise, or new competing products or manufacturers) add to this assurance.

CHANGES FOR 2000

The process for the 2000 metrics was easier in Massachusetts than in previous years since no one wanted to duplicate the six months of negotiations that had occurred in prior years. However, while most issues were resolved in 1999, several issues have dragged on for months with the result that as of mid-May 2000, the full metric package for 2000 has yet to be finalized. In Massachusetts, in negotiating metrics for 2000, there was a decided shift away from incentives for development of market studies or plans. While metrics for these types of specific activities had worked fairly well in 1998 and 1999, there was a philosophical shift (on the part of the NUPs) away from paying for activities that should be part and parcel of overall program activities. While in 1999 incentives were paid for developing long-term vision and preparing new types of evaluation products, the NUPs believed that these activities needed to simply be included as part of overall program operations.

As part of the development of metrics for 2000, NEEP developed a series of "key market indicators" for each program area that focused on measuring market progress (as opposed to items more directly in the hand of program operators) across six different generic types of market indicators. (These generic indicators were market share, price changes, emergence of new products, improved availability, awareness/attitude changes, changes in common practice, leverage of investment, and adoption of labels, codes, or standards.) While the utilities felt that these indicators were useful for program planning and evaluation, it does not appear likely that many of these market indicators will be adopted for metrics because of the utilities' desire to keep the metrics simple and more directly related to program activities. Many residential program metrics are now based on market share data. Market share numbers are most likely to be used when overall market size data is tracked by somebody else, such as the Association of Home Appliance Manufacturers (AHAM). Because of more limited market data in the commercial sector, metrics tend to be based on rebate activities or accomplishment of key program goals (e.g., offer and enroll customers in training and/or complete pilot projects).

In California, the focus in 2000 has shifted somewhat towards market effects, with this category now accounting for approximately 45 percent of the available proposed incentives in PG&E's service territory. As shown in Table 1, over the 1998 to 2000 period, milestones have changed significantly in structure. The revisions do not involve mere tweaks of percent market share or adjustments of dollar amounts. In many cases, a brand new slate is used for setting the next year's milestones. While some inter-year flexibility and adjustment is advisable, wholesale changes of this sort cause a lot of extended and complex negotiations with no guarantee that the new metrics are a significant improvement on the old.

In the Northwest, no significant changes are planned for the year 2000. However, restructuring legislation in Oregon and Montana and the potential increase in funding from individual public utilities will undoubtedly have an impact on how metrics are developed and implemented in the 2001-2006 time period.

While the focus of this paper is on California, Massachusetts, and the Northwest, in 2000, there have been important incentive developments in the Northeast that are also worth mentioning. Specifically, New Jersey and Vermont have adopted performance incentives, while Connecticut is discussing how best to modify current performance incentives to better address market transformation programs.

In New Jersey, a recent settlement agreement between utilities and several public interest organizations calls for the utilities to administer market transformation and other energy efficiency programs and provides performance incentives to the utilities of up to 8 percent of the energy efficiency budget. The incentives were developed largely based on key milestones (e.g., events such as studies), although some incentives are based on program participation (e.g., number of participants in particular program aspects). There is a multi-year agreement on the incentive process, including agreement that incentives beyond the first year will focus on market effects (e.g., customer awareness and market share), but the actual detailed incentive structure in the agreement covers only the first year. One other interesting element in the agreement is that in most program areas there is more than one path to earn 100 percent of the incentive amount (e.g., the bonus elements might total 110 percent of the maximum bonus amount for a given program area) (NJBPU 2000).

In Vermont, the Department of Public Service hired a contractor to run statewide efficiency programs through a competitive soliciation. As part of the contract, the contractor is eligible to earn performance incentives. These incentives are "designed to reward superior performance by the Contractor in the overall administration and delivery of Core Programs." Three types of performance incentives were established — program result incentives (for successfully accomplishing aggressive targets for direct market impacts such as electricity savings or market penetration of specific technologies); market effects incentives (for demonstrated significant market transformation that is achieved through the work); and activity milestone incentives (for achieving milestones for rapid startup and/or infrastructure development) (VDPS 2000).

In Connecticut, under legislation adopted a decade ago, utilities may earn a rate of return on conservation and load management program expenditures. In 2000, following restructuring, this program is continuing. Historically, and in 2000 as well, this incentive is based on kWh savings from programs, including market transformation programs. However, while this structure was adopted for 2000, the Connecticut Department of Public Utility Control has expressed an interest in considering other metrics for future years (CDPUC 2000; Gordes 2000).

Discussion

Based on the above discussion and experiences, several common issues emerge across regions and merit further discussion.

Statewide vs. Single Utility

Many programs in Massachusetts and several programs in California are now statewide. In some cases, a single contractor is hired to implement the program in each service territory. In other cases, each utility hires a contractor to implement the program for just its service territory. In the Pacific Northwest, single contractors typically are responsible for program implementation across the four-state Alliance region.

Compared to stand-alone utility programs, these statewide and regional programs provide additional milestone-setting challenges and the trend in both California and Massachusetts is to establish the same milestone for each utility when there is a statewide program (common metrics across states are much less common). While common milestones seem ideal, some flexibility must be maintained. For example, when there are significant differences in market share or consumer awareness in different service territories, it may make sense to base the milestone on an agreed-upon parameter —for example, market share — but to set different numeric targets for each region. This will reduce the potential of a utility who did its job in its service territory from not attaining a milestone due to the poor performance in another utility's service territory.

Another problem to watch for during statewide programs with a single statewide contractor is widely differing milestones for each utility service territory. This could cause contractor management issues with the utilities all asking the contractor to do something different in support of meeting their individual milestones. This may result in: (a) a breakdown in the statewide approach and a gradual return to individual programs and the associated market confusion this brings, and (b) very difficult contractor/client relations and arguments among the utilities.

Negotiation Schedule

In California. the program planning process is often complicated by compressed schedules and filing deadlines that are not in sync with program planning timelines. For example, in a few program areas, the negotiations over program year 2000 milestones occurred prior to completing conceptual program design. This resulted in some programs being designed around the milestones. The preferred sequence would be to set broad program goals, design the program, and then discuss and agree upon appropriate near-term milestones.

Similarly, in the early years in Massachusetts, incentive negotiations would begin in the fall and drag well into the program year. More recently, parties begin getting together in the summer in conjunction with the program development process so that by fall the incentive-setting process is well along.

Duration/Timing

A lot has been written previously about the benefits of having multi-year program designs and funding approvals, due to the fact that market transformation may take five or more years for many technologies and markets (see for example Nadel and Latham 1998, Suozzo and Thorne 1999). Still, California and Massachusetts continue to go through an annual program planning and milestone-setting process. This one-year horizon has the unfortunate result of leading the negotiations toward short-term measurements that may not necessarily be indicative of market transformation. Some of the recent milestones in the appliance area have forced utilities to offer rebate-laden programs in order to achieve an aggressively set market share target or spending goal. This may simply cause a temporary, but non-sustainable, increase in local consumer purchases.

A further compounding factor in California is the delayed approval of program plans by the CPUC. Under the current system, several rounds of filings and hearings may be required prior to a CPUC final decision. As a result, the new year's programs often are not approved until well into the first quarter or even second quarter. This prevents the implementers from providing the targeted stakeholders such as the manufacturers and retailers with the needed information to manufacture, ship, and stock the desired products in time to meet the program roll-out timeline and objectives. The programs are often then placed in jeopardy of underachieving and missing milestones. This dynamic is another reason why an institution with its earnings on the line is less likely to agree to market-based incentives. Likewise, for the past three years, metric-setting negotiations in Massachusetts have not been completed until well into the program year, resulting in similar problems.

This situation was further complicated in 2000 when the CPUC bifurcated milestone and program approval in order to provide utilities with program and budget approval by January. While the improvement in program approval timing is a step in the right direction, the delayed approval of milestones creates additional difficulties and risks for the utilities. The CPUC held hearings early in 2000 to allow the parties who filed protests on the proposed milestones to pursue their concerns and is scheduled to issue a decision on the proposed milestones in the summer of 2000.

Manage by Milestone Tunnel Vision

Rigid milestones may lead to strict "management by milestone". This can easily cramp program designer and implementer's creativity as the program year unfolds. Since milestones are often focused on one aspect of a program, a program manager has incentive to give that aspect priority over other possibly important parts of the program.

Number of Metrics

Establishing the number of incentive metrics per utility presents another challenge. A large number of metrics makes the portfolio complicated and costly to verify. For example, it is not cost-effective to spend $10,000 tracking and verifying a $40,000 metric. In Massachusetts, in 1998, for some utilities, there were so many metrics that some metrics were worth as little as $400 to the utility. On the other hand, reducing the number of metrics requires high level market effect type metrics because is as only at the level of market penetration and other high-level metrics that the many factors contributing to a successful program come together in a single metric. This places large earnings on the few metrics that are established, which in turn puts more money at risk for utilities and/or raises concerns when regulators see large earnings tied to a single measure. Ultimately, most regions are moving towards having a small number of metrics per program. For example, in 1998 PG&E had more than 100 total metrics and in 1999 the number of metrics was reduced to about 50 since regulators found it too complex to track 100 metrics. The Northwest on the other hand has always had several metrics per program (typically on the order of 3-5), but since metrics are not used for determine financial incentives in a formal regulatory proceeding, it is easier to have a few more metrics. Also, even in states with regulatory incentives, more metrics can are included in regulatory incentives. Overall, the emerging consensus appears to be that in most cases it makes sense to have a few incentive metrics for each program, except some of the smaller/simpler programs that may have only a single metric. And it will often be useful to include a few additional metrics as part of the program evaluation process.

Interdependence of Regions and Markets

The success of some programs is dependent upon the actions of other regional market transformation organizations. While California is indeed a very large market, often national manufacturers are reluctant to produce a new energy-efficient product simply for the California market (let alone the Massachusetts market). Many programs require the coordination, participation, and funding by several large groups — such as California utilities, the NW Alliance, NEEP, and the New York State Energy Research and Development Authority (NYSERDA) — that cover large geographic areas, populations, and market transformation budgets. However, because participation of other regions is beyond their control, utilities in Massachusetts have been reluctant to use national-level metrics, even if key market effects (e.g., increased product offerings) are needed at the national level. In the Northwest, since metrics are not used for financial incentives, it is easier to have some national-level metrics where these are critical to regional initiative success.

"All or Nothing" vs. Tiered Metrics

In some cases a simple yes-or-no type of milestone is appropriate. You get the money if you did "x," you get no money if you didn't. In most cases, however, a tiered approach is more effective. For example, two or more tiers of earnings for a particular milestone (less money for a partial accomplishment) can be established. This allows utilities to continue to strive to deliver results even when a program's most difficult objectives become unattainable during the program year. A tiered structure helps utilities better manage their risk and has been accepted by regulators in California and Massachusetts.

Energy Savings

Except in a few cases, the current class of metrics do not include direct measurements of energy savings. In our opinion, this is entirely appropriate as market transformation programs are designed to achieve long-term changes in the market, and measurements of short-term energy savings frequently have little bearing on long-term success. On the other hand, the lack of short-term savings information makes it difficult to simply communicate to legislators, regulators, and others what is received for their investment. While short-term energy savings measurements are not adequate to fully capture the value of market transformation, improved projections of current and projected future energy savings may be needed to satisfy the requirements of some policymakers. For example, in the Pacific Northwest, energy savings per measure are carefully estimated each year based on market effects (e.g., market share) and previous impact evaluation results on savings per participant. Similar approaches may be needed in other regions.

Establishing Incentives for Market Effects

In Massachusetts and California, utilities have been reluctant to accept market effects metrics because achieving these metrics depends in part on developments in the market that are out of the control of program administrators. However, for programs to be successful in transforming markets, it is these types of metrics, rather than program activity metrics, that are most important. California will use market effects milestones to a significant degree in 2000. As utilities gain some experience with these metrics, hopefully they will become less controversial. Still, because market effect indicators pose greater risks to the administrators, it may make sense to revise the rewards accordingly. One option is higher incentive pools. Another option, which has been adopted in California, is to allow the sum of individual program incentive pools to exceed the total pool so utilities have multiple opportunities to earn the maximum total incentive. For example, six metrics can be set, with each worth $100,000, but the maximum incentive capped at $500,000. In this way, even if one metric is not reached, the maximum $500,000 incentive can be earned. By giving administrators several opportunities to win a prize, riskier metrics become easier to accept.

Incentive Amounts

In both California and New England, there were extensive discussions about incentive amounts in the early 1990s, leading to a resolution in which the maximum utility incentive that could be earned was approximately 10-12 percent of the DSM budget. In 1998-1999, these same percentages continue to be applied. However, in 2000, in both California and Massachusetts, some NUPs have argued that utilities are required by law to implement public benefit programs and that incentives should be reduced. As a result, the maximum incentive in Massachusetts is likely to be reduced to around 9 percent of the DSM budget,[6] while in California, a draft Public Service Commission decision calls for a 7 percent maximum incentive. Utilities are opposing this reduction and as of this writing, a final decision has not been made. If the incentives are reduced in California, the metrics may also need to be revised since utilities are inclined to take fewer risks if the rewards are smaller.

Also, if smaller incentives are approved in both states, it will be very useful to evaluate the results of incentives at the end of the year in order to determine whether the smaller incentives still motivate good program implementation, or whether the smaller incentives are as effective as larger incentives in motivating the desired behavior.

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[6] The proposed incentive percentage depends in part on the interest rate on Treasury Bills, and thus the percentage could be somewhat higher or lower than 9 percent depending on how interest rates change.

Lost Revenues

In many states, in the early 1990s, mechanisms were introduced to reimburse utilities for a portion of lost revenues attributable to utility-operated energy efficiency programs. These lost revenue recovery mechanisms often complement incentives — the incentives offer rewards for successful DSM programs while the lost revenue mechanisms remove much of the disincentive to DSM programs provided by traditional rate regulation. However, these lost revenue recovery mechanisms have proven complicated, contentious, and expensive. As a result, the general trend is toward gradually phasing out lost-revenue recovery mechanisms (for example, Vermont is now doing this). We endorse this trend but recommend that lost revenues be considered when setting the overall incentive pool.

Conclusions and Recommendations

Based on the discussion above, it is clear that we are still on the steep part of the learning curve regarding incentives for market transformation. Still, based on the experience to date, several tentative conclusions and recommendations can be made.

1. *Incentives are useful in states where utilities are the prime administrators of market transformation programs*. Incentives are attractive to private utilities and clearly drive behavior to meet incentive goals.

2. *Incentives are complex and must be developed with care*. Care must be taken to identify program objectives and develop incentive designs that reward achievement of those objectives without having perverse or unintended effects. Metrics should be worded so that it is clear how achievement of the metric will be assessed. The number of metrics should be large enough to reward key achievements but not so large that pursuing and monitoring achievements becomes difficult to manage. Typically, each major program should have a few metrics.

3. *Increased emphasis should be placed on market effect metrics*. Incentives in California and Massachusetts have tended to emphasize activities and not market effects. Since the objective of market transformation programs is achieving market effects, such effects need increased emphasis when establishing performance incentives. Furthermore, when incentives emphasize activities, utilities have little incentive to pursue other activities, no matter how successful these other activities might be or how unsuccessful the originally identified activities might be (however, activity-related metrics can still be included as a complement to market effects metrics). In setting market effects metrics, a multi-year approach may be useful, in which firm milestones are identified for one year and tentative milestones identified for several subsequent years so as to provide direction for long-term activities and to streamline the annual metric-setting process (the annual process would begin with tentative long-term metrics set the previous year). However, it should be recognized that market effects depend on much more than utility actions and thus utilities take a greater risk that

incentives will not be earned, no matter how well a utility pursues a program's objectives. To address this increased risk, higher incentives should be considered, or utilities could be given multiple chances to earn the maximum incentive (e.g., the maximum incentive is earned if at least 80 percent of milestones are met).

4. *Good data and market/evaluation research are an important foundation for incentives.* Good baseline data and market research are needed to establish reasonable expectations of program performance. Unlike resource acquisition programs where measurement studies were conducted primarily post-program implementation, market transformation studies must occur before and during program implementation to properly set baselines and track market movement. Therefore, it is critical that program planning and evaluation be integrated. Verification evaluations are also needed to assess program performance and help determine if metrics have been met.

5. *Incentive metrics are often best set through negotiation, but parties need to have adequate time and flexibility.* Since incentives are complex, careful consideration and discussion of alternatives should be allowed for. Given the complexities, negotiation among the principal parties will often achieve the best results. But negotiations take time and require all parties to be flexible. In negotiations that involve a large number of stakeholders, a third-party mediator or facilitator should be considered. Use of a third-party facilitator can reduce the risk of the process bogging down and allows all parties to focus on their key objectives without having to manage the complexity of the negotiation process. In addition, adequate time should be allowed so that negotiated settlements are finalized before the program year begins so as to maximize the time available for pursuing milestones.

6. *A modest level of incentives appears to be acceptable to a wide range of parties in the regulatory process.* Incentive amounts should be high enough to get senior management attention but not so high as to cause ratepayer/intervenor backlash. Until recently, maximum incentives on the order of 10-12 percent of program budgets met these criteria. In 2000, experimentation is beginning with 7-9 percent incentives but it is unclear whether these incentive levels will be high enough to have the desired impacts.

7. *Current incentive approaches have difficulty addressing the dynamic nature of the markets they are trying to change, and as a result, there is a need to experiment with modifications to current incentive mechanisms.* Current incentive approaches involve setting incentives at the beginning of the year and then evaluating specified milestones at the end of the year. But due to the dynamic nature of markets, there will sometimes be a need for mid-year program modifications, a situation which current incentive approaches are not designed to address. More importantly, success in market transformation often depends on developing creative interventions, but rigid predetermined metrics do not encourage this creative process. Thus, new approaches need to be developed and tried to complement existing incentive approaches by allowing creative and successful approaches to be rewarded, even if they are not a formal part of incentive milestones.

One possible model would to for each state to create an "expert evaluation panel." The expert panel would be the equivalent of an arbitration body composed of qualified but disinterested parties. The panel would serve in an advisory capacity and report to the state regulatory commission. This panel could facilitate the metric-setting process, help ensure that the needed studies and data required to determine if the metrics were obtained are being collected, and make final recommendations to the regulators on whether the metrics were met and what level of compensation (e.g., earnings) should be paid. Under this scenario, the expert panel would have the authority to make mid-course adjustments in the metrics and incentive levels. For example, should one utility program do really well and another program not do so well due to conditions beyond the control of the utility, the panel could take these facts into consideration and make some adjustments to the original metric-related compensation. Such an approach has been successfully used for the evaluation of research and development programs (see for example CCST 2000) and is worth considering for market transformation programs. For this approach to work, the panel's mandate would need to be carefully defined so that it could get its work done in a timely manner using the available resources.

These conclusions and recommendations are based on initial experiences with regulatory incentives for market transformation programs. As further experience with these incentives is gained over the next few years, these conclusions and recommendations can be refined and expanded. What is clear at this point is that incentives do motivate actions, and that further testing is needed to determine the best combination of metrics to motivate implementers to achieve the desired accomplishments. States and utilities should be encouraged to be innovative and experiment so that incentive designs and market transformation programs can improve and prosper.

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