Deployment of Distributed Generation for Grid Support and Distribution System Infrastructure: A Summary Analysis of DG Benefits and Case Studies

Analysis of Regulatory Disincentives to Utility Ownership/
Facilitation of DG and Remedial Policies
Task #4

Prepared for the

**New York State
Energy Research and
Development Authority**

Energy. Innovation. Solutions.
Albany, NY
nyserda.ny.gov

Mark Torpey
Senior Project Manager

Prepared by:

Pace Energy and Climate Center
Tom Bourgeois
Project Manager

and

Dan Rosenblum and Dana Hall

Synapse Energy Economics, Inc.
Kenji Takahashi
William Steinhurst

NYSERDA
Report 11-23

NYSERDA 10472

February 2011

TABLE OF CONTENTS

1. REVENUE DECOUPLING MECHANISMS (RDM)

Electric distribution utilities are the primary point of contact for consumers when procuring electric energy and power. Most customers acquire their retail electric energy services either through, or from, their local utility. A distribution utility obtains its revenues from the sale of delivery service to retail customers on their systems while a vertically integrated utility obtains its revenues from the sale of electricity supply to retail customers.

Customer demands for energy services can be met via numerous sources including;

- utility-delivered electric energy and power,
- more efficient buildings, appliances, and other energy using capital equipment that reduce energy and power requirements, and
- customer sited renewable generation or other forms of clean onsite power and combined heat and power.

To the extent that a customer reduces its annual purchases of utility services, whether vertically-integrated or distribution-only, will see a reduction in its revenues. Under traditional rate making, that reduction in utility revenues will translate into lower earnings for any utility that is recovering fixed costs through its energy or delivery charge, i.e. its rate per kWh[1]. More efficient use of energy at customer sites and customer sited clean DG and CHP will reduce utility sales. Where government policy requires a reduction in electricity sales and an increase in renewable DG and clean, high efficiency CHP, there is an inherent conflict between the interests of the utility and the interests of society, as expressed in public policies.

In this section we explore issues involved in aligning the financial interest of distribution utilities with the preferences of regulators for ever greater levels of energy efficiency and clean DG CHP.

In subsection 1 we describe the impact of sales reductions on utility earnings. The traditional model for compensating utilities for the services they provide creates a linkage between incremental (decremented) sales and increased (reduced) earnings.

In subsection 2 we explore the rationale for implementing a new model for compensating the distribution utility in the form of a revenue decoupling mechanism (RDM). The RDM ostensibly breaks the linkage between utility earnings and increased sales. In theory this business model will make the utility indifferent to lower sales occurring as a result of higher levels of efficiency and deployment of more DG/CHP.

Subsection 3 poses the question of whether or not the RDM is a sufficient mechanism for meeting social goals of increasing efficiency and DG/CHP. We note that making the utility indifferent to lost revenues from DG/CHP may not be a sufficient to motivate the desired behavior.

In the final subsection we explore certain incentives that may be required in addition to establishing an RDM to meet preferences for more clean DG/CHP deployment.

1.1 Impact of Sales Reductions on Utility Earnings

It has long been recognized that electric utilities experience a financial disincentive when promoting energy efficiency, renewable energy or clean distributed generation and combined heat and power programs within their service territory. When a state expresses a public interest objective in promoting energy efficiency, customer owned renewable generation and efficient combined heat and power this objective is in conflict with the utilities interest in maximizing earnings.

[1] Customer reductions in purchases of utility services during a limited number of peak hours generally do not translate into lower utility earnings because of the limited reduction in kWh revenues and because the utility may be able to either avoid peak hour energy and capacity costs or recover those costs from other customers or off-system sales.

In traditional cost of service regulation, the utility finds it profitable to increase sales (or avoid a decrease in sales) in the period between rate cases, as long as the marginal revenue from the sale exceeds the marginal cost of the kWh sold. For a distribution-only utility the marginal revenue is the distribution component of the retail rate. The marginal cost is the marginal variable distribution system costs per kWh delivered to serve the next increment of load.

In traditional rate making, which applies to most vertically-integrated and distribution-only utilities, rates are established in a periodic general rate cases. Utilities are given the opportunity to recover their revenue requirements for a "test year" through rates which are a mix of customer charges ($ per customer / month), demand charges ($ per kW) and energy or delivery charges (cents/kWh).

The test year may be a historical 12-month period or a forecast 12-month period. The revenue requirement is computed for the same period as the test year, includes all of a utility's' costs of doing business, and reflects certain types of changes from the test year, the types depending on the jurisdiction. Utility costs can be broadly categorized as variable costs (e.g., fuel related costs, variable operation and maintenance costs, some types of transmission charges), fixed operation and maintenance costs, and other fixed costs such as administrative and capital costs. In the terminology of utility regulation, the rate base is total cost of utility capital net of depreciation. A utility's rates are set based on a revenue requirement that reflects its variable costs (e.g., cost of fuel and purchased power for the test year sales), plus annual depreciation of capital plant (the initial cost of the capital plant divided by its average lifetime), annual interest on corporate debt, annual preferred dividends, as well as an opportunity to earn an annual return on the capital. Earning a return on capital is necessary to continue to attract equity investors to provide financial resources for the utility to invest in physical and working capital over time, as well as to be able to issue corporate debt at reasonable rates for those purposes. The return on equity may be thought of, roughly, as the utility's allowed earnings or profit. Utilities and their investors may focus on the return on equity (ROE) per share rather than on the total absolute amount of earnings.

The rates for most utilities are set such that they recover some portion of their fixed costs through their energy or delivery charge, i.e. the rate per kWh. The result is a rate per kWh that will provide the utility an opportunity to recover its variable costs, plus some portion of its fixed costs including an allowed return on invested equity, provided that its actual kWh sales are equal to the test year sales upon which the rate was set. (This also assumes that the utility's actual variable and fixed costs are less than or equal to those assumed in its revenue requirements.)

Therefore the rate (price) of a kWh sold includes a portion to recover ROE, which permits the utility to earn a return on its equity investment. If the utility experiences higher sales, all else equal, the utility will accrue a higher ROE. Alternatively, if the utility experiences lower sales than forecast in the rate case, then all else equal, the utility will experience a lower ROE than expected. The same holds true for revenues needed to pay interest on debt and preferred dividends. The only instance when the marginal sales will not contribute to increased profit is in the case where the marginal revenue (i.e., the distribution component of the retail rate) is less than the marginal variable distribution costs per kWh required to serve that incremental increase to the load.

A portion of each kWh sale is also allocated to the return of utility capital, i.e., depreciation. The return of capital is the remuneration to a regulated distribution utility for investments made in all of the equipment necessary for providing electric service, including T&D facilities, vehicles, control equipment, buildings and, if vertically integrated, generation plant. If these investments were "prudently made" and are "used and useful," the associated depreciation expense (and the corresponding portion of the above return) is allowed in the utility's revenue requirement and is reflected in its rates.

Energy efficiency investments providing electric energy services that function as a substitute for utility owned ("supply side") investments impinge upon the expansion of utility revenues and earnings in another sense. Providing electric utility services from regulated supply side sources requires the deployment of utility-owned capital. Utility fixed assets earn a rate of return. As noted above the regulator includes in retail rates what it deems a fair return on equity (or debt). In contrast to an unregulated business entity, a distribution utility (or a vertically integrated utility) can rely on its monopoly customer franchise as a source of revenue for its allowed costs, a much less risky situation than that of an unregulated business.

On the other hand, electric utility services from energy efficiency investments at customer premises do not employ utility capital. If the utility operates programs that encourage energy efficiency investments at customer premises they are in effect diminishing the size of their franchise. Wherever non-utility owned, demand side resources are employed as a substitute for providing electricity services that might have been provided by utility owned, supply side resources, there is a diminution of the potential size of the utility investment for that area. The service is being provided but the utility does not own the assets providing the service.

Capital used to deliver electric power earns a return. When the same service is provided via energy efficiency savings, there is no return to the utility, other than covering the costs incurred in providing the efficiency services. All else equal, from the utilities perspective providing energy services via energy efficiency is not nearly as profitable as providing services via delivery of electric power to end use customers. Similar observations apply to services provided by DER to the extent that they avoid or defer T&D investment. To the extent that a utility is or expects to be in a position to make additional investments on advantageous terms, this is a concern to the utility.

The two points can be summarized as follows. Under traditional electric utility regulation fostering reductions in energy use is at cross purposes with the utility's interest in:

1. maximizing its profit between rate cases, and
2. expanding the size of its asset base, thereby enhancing its revenue generating potential

As long as the marginal revenue ("MR", or the distribution portion of the retail rate) from the sale of an additional kWh exceeds the marginal cost ("MC", as noted above, largely comprised of marginal distribution system costs of serving the next increment of load) of supplying that kWh, the utility will increase its earnings by virtue of that sale or avoiding a reduction in sales. Electric distribution utilities are a very capital intensive business. It is generally the case that MR > MC, making an increase in sales profitable for the company, and consequently implying that a decrease in sales diminishes utility profitability.

1.2 Revenue Decoupling Mechanisms (RDM)

Several states that have expressed a public interest objective in expanding the provision of electric energy services via efficiency, distributed generation and demand response have at the same time called for an alternative ratemaking strategy that would facilitate this objective. Decoupling mechanisms are said to serve this purpose by creating an alternative regulatory design that removes the disincentives that the utility faces when there is a compelling justification for providing an increasing share of electric energy services via demand side, or efficiency resources.

With utility earnings linked to increased sales the utility has a potential disincentive to promote cost-effective energy efficiency investments at commercial, industrial and residential customer sites within their service territory. When efficiency investments are the least cost means for providing incremental energy services, this disincentive with respect to efficiency investments may create a conflict between the interests of the ratepayers within the service territory and the distribution company serving those customers.

The New York State Public Service Commission (NY PSC) found in Case 03-E-0640 that properly designed revenue decoupling mechanisms were needed to address potential disincentives to utilities promoting and implementing more efficient energy use.[2] RDM has been proposed by the NY PSC as a mechanism to align the interests of the supplier of electric energy services (the distribution utility) with the consumer of those services, the electric ratepayer within that company's service territory.

On April 17, 2007, the New York State Public Service Commission ("Commission") announced its support for utility revenue decoupling mechanisms[3]. In 2003 the Commission had initiated a proceeding to investigate potential

[2] See Commission Order Requiring Proposals for Revenue Decoupling Mechanisms. Issued and Effective April 20, 2007. Case 03-E-0640. information accessed at http://www.dps.state.ny.us/Case_03-E-0640.htm
[3] "PSC SEEKS MORE EFFICIENT ENERGY USE: -Utility Revenue Decoupling Mechanisms to Eliminate Disincentives-" Cases 03-E-0640;06-G-0746. April 18, 2007

disincentives in the current rate structures that impeded the promotion of energy efficiency; customer sited renewable technologies and other forms of distributed generation. In July of 2006, the Commission expanded this proceeding to encompass the state's gas utilities. A final Commission Order was issued and effective on April 20, 2007.

Based upon its review of the evidence presented the Commission found that current rate designs were acting at cross purposes with an overall state objective to encourage greater customer adoption of existing and developing technologies for the clean production and end-use of energy. As a consequence, the Commission directed the utilities to file revenue decoupling proposals in any ongoing and all newly initiated rate cases.

Commission Chairwoman Acampora made this statement in support of broad based decoupling mechanisms.

> "To the extent current design of utility delivery rates continue to link the recovery of utility fixed costs, including earnings, to the volume of actual sales, disincentives exist that limit the utilities' interest in promoting efficient energy use," said Commission Chairwoman Patricia L. Acampora. "Creating a mechanism to reduce or eliminate the dependence of utilities' revenues on sales, would thereby increase the utilities' interest in the promotion of customer initiated more efficient energy use. The resulting public benefits from new energy efficiency programs, renewable technologies and distributed generation could be substantial." [4]

The Commission approved implementation of a broad based decoupling approach, rather than the more limited Lost Revenue Adjustment Mechanism (LRAM) method. An LRAM attempts to true up estimated lost revenues attributable to a program or a suite of programs. The more broad based approach approved by the Commission required the utilities to submit mechanisms that would true up forecast and actual delivery service revenues. This approach is significantly more far reaching than a net lost revenue adjustment that focuses on identifiable losses from specific energy saving programs. It avoids complex debates over what lost revenues are attributable to energy efficiency programs and it practically eliminates a utility's incentive to oppose energy appliance standards and other state and federal measures that might reduce utility sales.

RDM has been identified as a mechanism for effectively breaking the link between utility annual sales and utility recovery of fixed costs and earnings.

In its broadest form, the RDM adjusts rates up, or down, outside of a general rate case. The RDM adjusts rates so the utility's actual annual revenues remain sufficient to cover the fixed cost portion (including ROE) of the utility's revenue requirement approved in its last rate case. For example, if revenues from sales fall short of the amount required to recover these fixed costs, the rate is adjusted upward to collect the difference. If revenues exceed the amount required to recover fixed costs, rates are reduced to return the difference to ratepayers. Put another way, by maintaining the recovery of fixed costs, RDM avoids increases or decreases to ex ante profitability.

There are many nuances involved in the design and execution of an RDM. The overarching objective is to create a regulatory mechanism that does not penalize utilities for reductions in delivered energy sales, when sales reductions are a state and social goal.

Some of the nuances in RDM design have to do with the extent of the protection that the utility receives. For example, RDM can be designed to shift business risks from the utility to the consumer. For example, sales fluctuation due to weather patterns is a risk (and reward) traditionally borne by the utility. If a summer is cooler than normal or the winter warmer than normal, then utility sales will likely fall significantly short of forecasts resulting in reduced earnings. On the other hand, if a summer is hotter than normal or a winter colder than normal, then utility sales will likely rise significantly above forecasts, resulting in increased earnings. Likewise, if economic conditions embedded in a sales forecast were overly optimistic and realized economic activity falls short of the forecast, then utility revenues and targeted rate of return will not be realized. If economic conditions embedded in a sales forecast were overly pessimistic and realized economic activity exceeds the forecast, then utility revenues and targeted rate of return would be greater than expected. RDMs can be designed to address this shifting of weather risks and other economic development risk.

[4] ibid, page 1

Other issues of concern are the extent to which the utility is made whole for divergences from projected sales. At one end of the spectrum is the more limited Lost Revenue Adjustment Mechanism (LRAM). In this approach rate adjustments are limited to truing up for sales reductions that are demonstrably a consequence of utility-run programs designed to lower sales. At the other end of the spectrum is the full true up of actual to forecast sales. In this instance, there is no need to determine how the sales reductions occurred. Reductions may be due to codes, standards, naturally occurring efficiency gains, or any other source. Supporters of the more broad based approach note that this approach has lower oversight and compliance costs, is less subject to gaming and it does not penalize the utility for sales reductions due to building codes and higher efficiency standards. The supporters point to the fact that in many instances utilities have opposed tighter codes and standards.

1.3 Decoupling Mechanisms Do Not Fully Address Utility Concerns with CHP Development

A broad based RDM removes the explicit disincentive created by the lost revenues that occur with the removal of that portion of the customer load once served by the distribution utility. Still, it fails to address numerous other issues that may affect the operations and the future profitability of a distribution utility.

1.3.1 Impact of RDM on Utility Perspective on CHP

New CHP projects should benefit at the margin from the institution of full decoupling mechanisms. A full decoupling mechanism is one that “true ups” forecast and actual delivery service revenues. This is the type of approach that the Commission approved in its April 20, 2007 Order.

The type of broad based decoupling prescribed by the Commission removes one major obstacle to the development of CHP within electric distribution utility service areas. It may be seen as a necessary, but not sufficient policy approach for facilitating the more rapid deployment of economically viable, environmentally preferred customer-owned CHP[5].

1.3.2 Remaining Barriers to utility support for CHP

Customer side, CHP is a substitute for the power delivery services of the distribution utility. When customers remove a significant portion of their energy and capacity demand from the distribution system, for 4,000 to 8,000 hours per year, they are at the margin shrinking the size of the utilities franchise. Even with compensation for the loss of revenues the utility continues to be worse off with increasing levels of CHP as it lowers the future earnings potential of its franchise. The worth of a corporation is the discounted future value of its earnings. Increasing levels of CHP reduce the future earnings potential of the enterprise by shrinking the scale of operation.

Above and beyond RDM, utilities will likely require incentives in order to meet accelerated resource acquisition targets. States interested in markedly increasing the rate of distributed energy resource growth have recently paid greater attention to a portfolio of measures that would better align the distribution utilities interests with those of policy makers and ratepayers. This portfolio of incentives is likely to include RDM as well as incentives that provide the utility with a higher profit upon meeting certain agreed upon targets.

There are several reasons why simply breaking the link between sales and earnings is likely to be an insufficient incentive to change the rate of growth of DER investments in a really meaningful way. We explore several of these reasons in this section.

[5] Such sites may be customer or third party owned and/or operated. The key distinction creating additional electric distribution utility disincentives is attributable to the fact that the utility has no ownership stake.

1.3.3 DG CHP Capital May Be Less Profitable to a Utility than Utility-Owned Capital

This research study is focused on examining the possibilities of DG/CHP as an alternative to utility distribution capital investment. From society's perspective we can envision many plausible situations where a DG CHP or DER solution could provide a substitute for utility capital investment in the distribution system and do so at a lower cost to ratepayers. Nevertheless, from the utility's perspective instances of this sort may represent a loss in future earnings potential. RDM breaks the link between sales and earnings but it does not break the link between rate-base and future earnings potential. Under the current system of utility cost recovery, increasing the rate of substitution of DG/CHP assets in place of new utility investment means an increase in the diminution of the utility's franchise. This issue will be explored in more detail in the next section as we examine rate-basing utility investments in DG/CHP.

In contrast to the above argument we note there are some instances that DG/CHP projects are viable alternatives to T&D projects and may be seen by the utility as in the best interest of investors. For example, when T&D projects face obstacles, such as delay in project schedules due to environmental concerns, local opposition, and so on, DG/CHP and DSM could be beneficial to maintaining reliability of the electric system. In other instances a utility may be capital constrained and could welcome a solution that does not require them to raise additional capital – particularly when the environment for project financing is difficult.

1.3.4 Distribution System Planners are not Trained to Identify DG CHP Solutions

Using DG/CHP assets in distribution system planning has not traditionally been part of the operations of distribution utilities. There is an inertia that exists in the form of years of education and training in supply side methods. The existing tools familiar to distribution system planners are not designed to capture DER solutions. There is an existing investment in simulation models, routines and staff planning, design and operation experience that has to be redirected in order to fully take advantage of DG/CHP system solutions.

The retraining of staff and the retooling of existing methods and procedures is not costless. A change of business practice requires investment. Unless the utility is specifically compensated for this retraining of their human capital assets they will likely view such changes skeptically.

In this section we have underscored the point that there are some very pragmatic reasons why the distribution utility would be averse to substituting DER resources for traditional capital expenditures in the T&D system.

1.3.5 DG CHP Resource Acquisition is not the Utility's Core Business

Discovering DG CHP assets to substitute for distribution system capital investments is a time consuming process requiring the employment of the utility's human capital resources as well as specialized assessments requiring modeling and analysis tools. This is not a costless exercise. In our conversations with affected parties we have heard that one of the major issues with utility DG/CHP developer relationships is timeliness and responsiveness. From a development standpoint delays in a project's timetable and uncertainties in project costs can be fatal. From the utility's perspective, making time to review and respond to developer requests takes time away from other activities. There may also be conflicts in system resource decisions between the needs of the DG/CHP developer and the utility's assessment of what is optimal. A case in point is the "red zones" in the Con Edison service territory. There are a number of areas within New York City where DG/CHP deployment is severely curtailed unless and until Con Edison makes necessary system upgrades. The schedule of upgrades that Con Edison has set forth has been criticized by some as being a hindrance to the development of viable and socially beneficial DG/CHP investments.

1.3.6 Risks Inherent in Lack of Control over the Assets

When a DG/CHP solution is put in place in lieu of a traditional utility capital investment, the utility still shoulders the responsibility for insuring the reliability of the system. When the ownership and operation of the asset shifts from the control of the utility to the control of an external party, the utility is bearing an increased risk. The primary focus of the utility is on the provision of safe and reliable service. Utilities are penalized for loss of service and for lapses in service quality. Utilities have expressed concerns regarding these types of issues that arise when ownership and control of the asset is taken out of their hands:

- Guarantees that the DG/CHP will run when required
- The ability to run the DG/CHP asset in a manner that optimizes the utilities needs
- Information on the assets likely performance
- Control over the maintenance schedule

These issues are not insolvable. Some can be addressed by legal contracts. Still, the point remains that when the responsibility remains with the utility, but the asset is removed from their control, a greater level of risk is borne by the utility. In the final section we examine the prospect of utility ownership, which is also a solution to this problem. Nevertheless, utility ownership of distributed energy resources (DER) has consequences that must be considered in the broader context of promoting efficiency, competition and innovation.

1.4 Utilities may Require Incentives to Support Accelerated CHP Development

States interested in markedly increasing the rate of distributed energy resource growth have recently paid greater attention to a portfolio of measures that would better align the distribution utilities interests with those of policy makers and ratepayers. This portfolio of measures is likely to include RDM as well as incentives that provide the utility with a higher profit upon meeting certain agreed upon targets.

These additional incentive measures include the following:

i. cash rewards for achieving and exceeding savings goals, often stated as a percentage of savings
ii. incentive payments based on kW of DER assets installed in a performance period (e.g. $150/kW for all DG operational in a calendar year)
iii. capturing a percentage of savings of the DER investment as compared with utility investment (e.g. utility investment cost is $550/kW , DER solution is paid $400/kW, utility keeps $150/kW)
iv. rate-basing and return on eligible customer Utility Ownership of the DG Resource

Proponents of RDM as well as affected DG stakeholders agree that one or more incentives in addition to an RDM are required to reach significantly higher levels of clean DG penetration. As noted in the chapters above, simply breaking the direct link between increasing sales and increases in earnings is not a sufficient condition for encouraging greater levels of DG penetration on the existing utility distribution systems.

1.4.1 Incentive Payments Based on Installed Capacity in a Performance Period

In order to stimulate greater utility interest in DG/CHP some regulators have put in place an installed capacity incentive for the utility. For example the State of Connecticut in June 2005 passed legislation (Senate Bill 7501) that provided incentives for utilities to facilitate the installation of distributed generation (including CHP) within their service territories. Under the legislation, a utility would receive an incentive payment to “educate, assist, and promote investments in customer-side distributed resources developed in such company’s service territory.” When implemented in 2006, the size of the incentive payment was $200 per kilowatt. Each year thereafter, the incentive decreases by $50 per kilowatt until 2010, when the incentive payment becomes $50 per kilowatt. The payment is made at the time the resource becomes operational.

If utilities, their regulators, and affected parties identify cost saving DG/CHP investments on the distribution system, the utility could capture a reward in the form of retained savings. Such a reward structure might direct the utility towards identifying the highest value DG/CHP resource solutions. For example, suppose a fixed payment of $300/Kw-year was set on DG CHP investments that are deemed a substitute for a proposed utility investment. If this were the case, avoided utility distribution system costs of $600/Kw-year would net the utility a $300/kW-year bonus; similarly avoided distribution system costs of $400/Kw-year would net the utility a $100/kW-year bonus.

The non-participating ratepayer does NOT receive a benefit in this scenario as all of the gains are split between the utility and the DG/CHP owner. Nevertheless, as long as avoided costs are accurately characterized and the DG/CHP solution does not increase costs over the utility investment case, then the non participating ratepayer is no worse off.

1.4.2 Permitting Utilities to Rate-base and Earn a Return on DG CHP Investments

If a utility has the choice of addressing a T&D investment with two equally effective measures, and if one measure is utility owned and the other owned by an external party, the utility owned measure will tend to be preferred by the utility, at least in those situations where it has ready access to capital. With utility ownership comes the right to rate-base the measure earning a return of the original capital investment and return on the equity portion of the investment (profit). A measure sited at a customer facility and paid for by the customer or a third party developer produces no expansion of the capital base of the utility. Over time, as customer sited T&D assets substitute for utility assets, the capital base and subsequently the earning power, of the utility is smaller than it would otherwise have been.

This is an important disincentive that RDM alone does nothing to address. The future earning power of the utility is linked to the size of its asset base. A DG/CHP program as a substitute for T&D capital investment inevitably leads to a smaller asset base then the status quo without such a program.

On the other hand, scenarios clearly exist where the utility would prefer not to invest its own capital for a variety of reasons. It may be that capital solution proposed by the utility is more costly in terms of time, effort and public image than would be the DG/CHP solution. In dense urban areas for example, utility construction may meet with public opposition, may be delayed for long periods in the codes siting and permitting process, and otherwise be subject to other unforeseen costs and disruptions. Likewise, if the utility is capital constrained, if the cost of capital is high and availability of capital tight, the utility may prefer a customer based DG/CHP solution.

The issue of ownership is a complex one. If the distribution utility is permitted to own the DG/CHP resource many of their stated concerns, such as asset control, dispatchability, or asset reliability, are all greatly diminished, if not eliminated.[6] The utilities have expressed a concern that in the absence of physical control over the resource, they will be at risk that the DG/CHP owner may choose not to run when needed, for whatever reason. The asset may not run for an economic reason, or as an operational decision, or for any number of reasons that are germane to the end-use customer. Another concern that has been voiced is dispatchability. The way in which an end user might run the system at a particular time may not be the optimal manner in which the utility would run the asset, were the asset under the utility's control. The issue of maintenance and reliability has been put forward as a concern. The utility asserts that they take on some risk in not knowing the reliability of the asset. Were the asset under its control they would have full information regarding the schedule of maintenance and the expected performance of the asset under various operating conditions.

There may be some information gains to be had by allowing the utility to own the DG/CHP resource that is serving as a substitute for distribution capital investment. Lack of information and lack of control raises the performance risk for the utility. Ownership greatly diminishes the risk. It does so at a potential cost to those who compete with the utility by offering DG/CHP project development services. As a regulated entity with access to system and customer information that others do not possess, the utility has a dominant position in the marketplace. This position of dominance might be used to undermine real competition in the provision of DG/CHP services. The loss to society in this case is one that is hard to quantify, but may nonetheless be quite real and possibly substantial. There is a risk that if the market is captured by a dominant player, costs may be driven up due to a lack of real competition while innovation, product and service quality may suffer.

[6] A case in point is Detroit Edison. As discussed in Section 1, Detroit Edison has been aggressively purposing utility owned mobile DG units to solve a number of distribution problems.

Summary

In this task we have reviewed the rationale for instituting a revenue decoupling mechanism. The RDM is designed to break the link between sales and earnings. This linkage is a clear disincentive to the utility that is required or who chooses to promote programs such as energy efficiency and DG/CHP (collectively "DER") that involves a loss of utility sales.

The RDM removes a disincentive but does not create an incentive for the utility to acquire DER assets. Policy makers are expecting DG/CHP and other DER assets to play a markedly expanded role in the future energy system in New York. In order to meet these goals the rate of increase of DER resource acquisition will have to accelerate.

For a variety of reasons explained in the sections above, RDM alone is not likely a sufficient mechanism to create a rapid acceleration of DG/CHP deployment. There are disincentives that remain even with the implementation of an RDM. These disincentives include but are not limited to the following:

- DG/CHP capital may be less profitable to the utility than utility-owned capital
- Distribution system planners are not trained to identify DG/CHP solutions
- Systems planning and analysis software and methods and procedures typically do not consider DG/ CHP solutions
- Risks inherent in lack of control over the assets, and
- DG/CHP resource acquisition is not the utility's core business

It appears that incentives in addition to RDM will be required in order to encourage distribution utilities to capture the benefits; including the potential T&D avoided cost benefits, of DG/CHP in their service territories. Proponents of RDM as well as affected DG/CHP stakeholders agree that a suite of incentives, in addition to an RDM, will be required to reach significantly higher levels of clean DG/CHP penetration.