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Decoupling Utility Profits from Sales

SEPA

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Decoupling Utility Profits from Sales:

Issues for the Photovoltaic Industry

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Letter from SEPA Leadership

February 2, 2009

Utility and Solar Colleagues,

We are pleased to release a new report, "Decoupling Utility Profits from Sales: Issues for the Photovoltaic Industry," the third SEPA report of 2009.

SEPA bridges electric utilities, solar companies and other stakeholders to push solar forward more tangibly, one real business at a time. From research projects and national conferences to one-on-one counseling and peer matching services, SEPA's unique joint partnership offers members critical access to key business relationships and unbiased, actionable intelligence needed to make solar practical and profitable in today's shifting energy landscape.

Decoupling is a complex subject. It requires a major change in the regulatory process for the utility, regulators, and intervening stakeholders. But it is emerging in state and national discussions as a means to address the clear disincentive that photovoltaics, and other forms of on-site energy generation and conservation, can pose to utilities. In a nutshell, if the utility sells less electricity, it may fail to cover its fixed costs and possibly make less profit. As a corporation, this presents a clear hazard to the long-term business strategies as they apply to customer-sited solar systems.

While energy efficiency is the major driver of decoupling initiatives, the photovoltaic industry has a place in the discussions. We hope this report defines the issue and creates necessary dialogue for the long-term health of the utility and solar industries.

If you have any suggestions or comments, feel free to contact either of us.

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Introduction

The US has seen a rapid increase in interest in virtually all forms of demand-side distributed resources (DR), including energy efficiency, load management and on-site electricity generation (DG). An increasingly popular DG resource is the installation and use of photovoltaics (PV).[1] The number of grid-connected U.S. PV installations grew 46% in 2007 to a cumulative 473 megawatts (MW) at over 48,000 locations[2]. Rapid growth is expected to continue and by 2010 these numbers are estimated to increase to over 1,350 megawatts at over 116,000 locations, and more than double again by 2013.[3] While only one part of many demand side resources, PV is growing rapidly, particularly in western and northeastern states.

The vast majority of these PV installations are sited at homes or businesses on the customer-side of the meter, directly offsetting onsite consumption at retail rates through a policy known as net metering.[4] Net metering is currently available in 43 states, and is defined in the size, scope and customer eligibility by state or utility guidelines, but is most ubiquitously available for the residential customers of investor-owned utilities.[5] Utilities' operating history with net metering policies ranges from none at all to over 20 years, and utility perceptions about the policy range widely from opposition to support.

To the PV industry, net metering has represented an elegant policy solution for increasing solar customer benefits, eliminating the need for batteries, and approximating utility accounting conditions similar to energy efficiency. To the utility industry, net metering opens up concerns about potential fiscal and policy impacts, blurring the lines between utility customers and generators. To society at large, PV can address both public goals and policies to reduce customer electricity bills, generate clean renewable electricity, stimulate economic development in new technologies, reduce the peak demand for electricity, and improve system efficiency by generating electricity close to the load. While important to many stakeholders, to the utility these social benefits accrue outside their business environment, are difficult to calculate and are commensurately discounted when quantified. What is clear is that net metering implementation and interpretation has been and can be a contentious regulatory issue which will require adjustments as the PV industry grows.

One key issue in the net metering policy debate is the loss of retail electricity revenue, i.e. customers who generate their own electricity and offset their consumption at retail electricity rates pay lower electricity bills and reduce the amount of electricity revenues collected by the utility. Reduced revenues have a direct impact on all utilities' recovery of costs associated with each customer, and for regulated utilities, profits. The impact is minimal at the current low PV penetration levels, but played out on a theoretical basis to a high percentage of customers, net metering will likely become a measurable issue in the future.

[1] Most of the issues discussed in this decoupling paper about photovoltaics (PV) are common among other demand side distributed resources, including energy efficiency, load management, and distributed generation. References to distributed generation assume net metered configurations, while references to distributed resources include both energy efficiency and distributed generation.

[2] It is worth noting that in 2002 the ratio of grid- versus off-grid PV markets was approximately 1:1, while in 2006, the ratio was nearly 3:1, a trend that will continue. Source: Interstate Renewable Energy Council (www.irecusa.org).

[3] All solar megawatts cited are DC-ratings; approximate derating to AC capacity would be 80-85%, depending on the calculation method, installation details, and geographic location.

[4] In the United States, net metering remains the dominant metering configuration. This is in contrast to several announcements by U.S. utilities for new customer-sited, utility-side of the meter installations, which are interconnected directly to the distribution grid and are not net metered, with no effect on the customer's electricity bill and therefore revenue-loss. The utility side of the meter configuration is quite common in Europe (though with customer or investor ownership instead of utility), where feed-in tariffs are the primary policy driver of PV systems.

[5] The Energy Policy Act of 2005 requires all state utility commissions to finalize "consideration" of standards for net metering by August 8, 2008. The Interstate Renewable Energy Council is actively tracking these proceedings online through their "Connecting to the Grid" project (www.irecusa.org).

Revenue loss may seem like an issue that utilities simply need to adapt to within their business environment. The energy delivery and sales business may shift over the long-term as distributed generation, energy efficiency, storage, smart grids and meters, environmental regulations, and restructuring evolve. However, the utility's functions of developing and maintaining a core infrastructure of generation, transmission, and distribution investments will remain a necessary part of the electricity system. As will be discussed below, revenue loss has real impacts on utilities' profits, which played out at a measurable scale, would affect their ability to obtain credit from investors for maintaining and expanding the energy infrastructure at a minimum, and at worst affect their solvency.

To be clear, net metering concerns are not driving policy responses to revenue loss, and revenue loss is not currently an all pervasive issue nationwide. Instead, a combination of energy efficiency programs, fluctuating customer consumption from weather and economic conditions, distributed generation such as photovoltaics, and the changing dynamics of the energy industry are causing decoupling—a particular public policy response to revenue loss—to percolate into broader public policy discussions at public utility commissions, state legislatures, and at the federal level.

This decoupling white paper stays neutral on the topic, instead providing an overview of the problem with revenue loss and a background on net metering and its specific impact on the problem. The paper then goes on to more specifically define and discuss decoupling and alternatives to decoupling. This is followed by a decoupling case study of a hypothetical utility[6], which shows the relative magnitude of decoupling overall and estimations of the impact of photovoltaics from a renewable portfolio standard that includes a solar specific requirement.

Utilities and Revenue Loss

"Is revenue loss and a reduction in utility profits such a bad thing? Shouldn't they have to adjust to changes in their business environment, just like the computer or phone industries?"

The proverbial "paradigm shift" from centralized to distributed energy is often cited in the debate about the electricity industry's future. Whether and to what degree this may occur remains to be seen. However, a decline in utility profitability (or the inability to cover costs) due to a host of external pressures, would eventually impact the average consumer.

Regulation of utilities is almost universally based on a cost-of-service concept in which the total cost to serve customers, including returns to equity investors, are administratively determined and then collected over the associated units of consumption. In the long run, even if consumption is lowered, the fixed costs will still be collected when each new rate case is completed. In between rate cases, however, reductions in revenues result in reduced earnings. If the utility consistently incurs this reduction in earning, it will likely experience lower credit rating and a higher cost of capital, which translates into a higher cost to serve customers. It will also be highly incentivized to avoid or prevent deployment of customer-owned generation and energy efficiency. This is the case in most states in the US today.

[6] Billing and consumption information for our hypothetical utility is based on actual billing data previously provided by PPL, a Pennsylvania utility, to RAP for the Mid-Atlantic Distributed Resources Initiative (MADRI).

Utility Cost and Pricing Structures

Investor-owned electric utilities[7] are typical businesses in many respects. Increased electricity sales means increased revenues, and by association, profits. As a result, utilities have a strong incentive to increase sales and limit activities that reduce sales. This simple relationship captures what is typically called the utility's "throughput incentive," which can work against competing public policies that support energy efficiency and distributed resources. The throughput incentive is inherent in the way regulation works in many states and the magnitude of its impact is inherent in the way utilities operate and are capitalized.

Virtually all reductions in customer consumption will drive reductions in utility revenues. Customer-owned generation, demand management (typically load shifting and peak reduction) and energy efficiency all have the effect of reducing energy or demand and therefore, customer bills and utility revenues. Customer trends, especially the growing PV energy generation market, are important to a utility's expected revenue and financial health outlook.

UTILITY COST STRUCTURES

Utilities have two significant characteristics that combine to make their profits especially sensitive to changes in revenues. First, utilities typically have substantial operations and maintenance (O&M) and financial costs, which do not vary directly with consumption of electricity.[8] Many of these expenses are related to the extensive generation, transmission and distribution facilities operated by the utility, which need to be built and maintained regardless of specific electricity volume changes. Second, the capital structure of utilities tends to be significantly financially leveraged, which has the effect of making profits more sensitive to changes in revenues.

Virtually all of a utility's profits derive directly from utility-owned assets through an administratively determined return on equity (ROE).[9] Typical investor-owned utility capital structures have more debt than higher risk ventures, around 40%-45% equity and 55%-60% debt and perhaps as much as 10% preferred equity. This has two effects. First, it adds to the fixed nature of the utility's cost structure in the form of interest on the higher debt. Second, because the equity investment is a relatively smaller part of the capitalization, the dollar magnitude of earnings is proportionately smaller. For a small utility with a rate base of $200 million and a total revenue requirement of around $180 million, the total return on equity, or profit, may be as little as $10 million, or 5.5% of total revenues.

HOW ELECTRICITY PRICES ARE SET

Utility electricity prices are theoretically designed to recover an authorized revenue requirement, which is reflective of the costs incurred to provide service to customers including a commission-approved utility profit margin. To determine the price to be charged, regulators add up the expenses of the company and calculate the revenue needed to cover investment related expenses such as interest on debt and return on equity. The sum of these, the revenue requirement, is then allocated among the customer classes, i.e. residential, small commercial, etc, and is usually based on some combination of the number of customers and their class contributions to annual or monthly peak demand and energy. Prices for an individual rate class are derived by first allocating the revenue requirement for each customer class among the types of prices, e.g. billing, metering and other customer service costs may be allocated to the customer charge.

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[7] The paper largely focuses on regulated investor-owned utilities, but cooperative and municipal utilities do utilize rate pricing structures designed to recover revenue equal or greater than their costs and decoupling would be an applicable method for revenue recovery.

[8] Many of the issues related to decoupling hold true for electric and natural gas utilities, but the focus of this paper will be on electricity only.

[9] Utility assets typically include transmission and distribution facilities and, except for "wires only" companies, generating equipment, as well as a host of other plant and equipment such as vehicles, meters, etc.

Under traditional regulation, consumer prices are recovered through either volumetric ($ per kilowatt and/or kilowatt-hour) or fixed charges ($ per month). In the electric sector volumetric charges are generically referred to as "energy rates" ($/kWh) and "demand rates" ($/kW).[10] To calculate energy rates, the metered consumption for the class for a known period (the "test period," a consecutive twelve month period) is divided into the allocated portion of the authorized revenue requirement. In simple terms, prices are set on a "class" basis, by dividing the revenue requirements to cover costs by sales volumes for each customer class. These prices are generally set once at the end of a rate case and remain in effect until the conclusion of the next rate case, which may not occur for five or more years.

The Utility Ratemaking Formula

Electricity Price = Revenues ÷ Units Sold

Revenues = Operating Expense + Interest on Debt + Return on Equity + Taxes

Total utility revenue requirements are allocated among rate classes, usually according to a combination of number of customers in the class, and the class demand (kW) and energy consumption (kWh):

Class Volumetric Prices* = Class Revenues ÷ Class Consumption*

* In $/kW or $/kWh, or kW or kWh, respectively

NOT ALL REGULATED UTILITIES ARE THE SAME

For our purposes, there are two types of regulated utilities – those with costs that, between rate cases, generally do not vary with consumption, and those with some costs that do vary with consumption. There is also a high correlation between cost variation and whether the utility operates in a restructured jurisdiction with formal wholesale markets and whether the utilities are vertically integrated or not.

Many utilities in restructured jurisdictions have divested their generation (or transferred it to an affiliate). These companies can be generalized as distribution or transmission ("wires-only") companies, who own little or no generation. The primary asset base and functions are built around the delivery of energy from wholesale commerce into retail commerce. To the extent they are involved in the procurement of the electricity (e.g. in the procurement of standard offer or default services), they usually earn no profit margin from its sale.

The principal "profit" operations of these utilities are comprised of the authorized profit margin associated with distribution infrastructure investment. For the most part, residential and small commercial customers are served through some form of standard offer service, with large customers often purchasing directly in the wholesale market or through third-party energy service providers. Utilities may experience various situations regarding customer growth and customer usage, and the pricing and authorized revenue requirements for these "wires only" companies will depend on the states' ratemaking rules.

Vertically integrated utilities have a higher portion of variable expenses, in the form of fuel and variable O&M because the production costs of generation vary directly with output. This means profits are less sensitive to the same percentage change in total revenues than for "wires-only" companies. If a vertically integrated utility also has a fuel cost adjustment clause, changes in fuel cost are passed through to customers and changes in those costs will not impact the utility's profits.

[10] There are other charges on the bill, as well, including customer charges and power factor charges. However, these typically are small relative to the volumetric charges.

SALES VOLUME AND PROFITS

The combination of a utility's cost structure and the manner in which authorized revenue requirements are set, can mean that while costs remain relatively unchanged with consumption changes, revenues (and therefore profits) do not. For a traditional vertically integrated utility that owns its own generation, transmission and distribution system, small changes in sales volumes (units of energy or demand) translate into significant earnings changes.[11] For example, a 5% change in revenues may increase or decrease earnings by more than 35% (Figure 1).

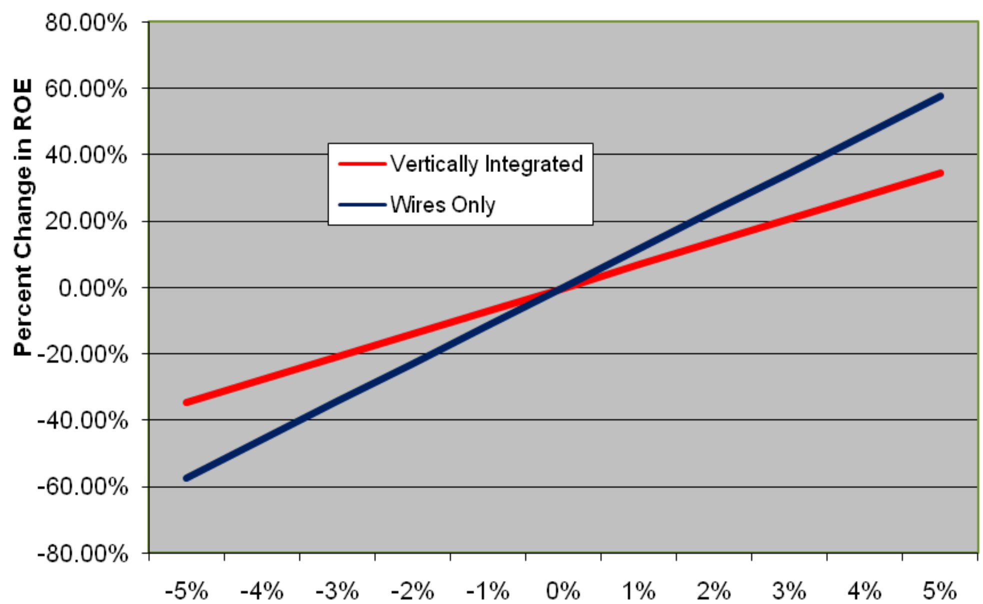


FIGURE 1: Impact of Revenue Change on Return on Equity (ROE)

For wires-only companies the sensitivity of profits to changes in revenues is even greater – a nearly 60% increase or decrease in profits for the same 5% change in revenues. In either case, absent regulatory intervention, the exposure of profits to revenue reduction risk is significant.

CUSTOMER TRENDS

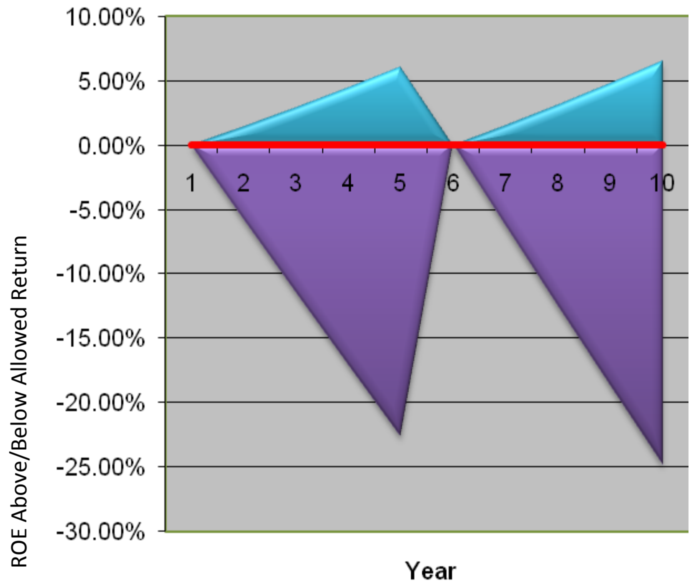
In addition to cost structure issues, sales trends over time are important in determining the financial health of utilities. Currently in the U.S. electric utilities generally experience increased sales per customer over time. Gas utilities, on the other hand, are experiencing decreasing sales per customer over time. One of these two trends tends to be strongly evident in most utility companies.

In many jurisdictions regulated prices are implemented on a "set it and forget it" basis. The regulatory process uses a cost-of-service approach (outlined above) to determine the price, which includes estimations of costs, sales, and revenues. The resulting prices remain unchanged until the end of the next rate case, but the actual sales volumes *will* be different than the estimated values used to set the working prices. As a result, actual revenues will be higher or lower than the estimated amount calculated in the rate case.

There is usually no reconciliation of the actual differences, that is, any over- or under-collections are not compensated back to the ratepayer or utility respectively, although each new rate case should approximate a recalibration to match the current cost and pricing conditions. As a result, during the period between rate cases utilities with increasing trends in sales (generally electric utilities) will

[11] In this example, we have assumed a wires-only distribution company with a $200 million asset base, capitalized with 45% equity and 55% debt, at a cost of 11% and 8%, respectively. The "allowed" profit for this utility would be $9.9 million.

tend to see an increase in actual earned returns.[12] Those utilities with actual sales numbers lower than forecasted sales numbers (typical of gas utilities) will see a reduction in earnings between rate cases. In both cases, other factors, especially general customer growth, inflation in expenses and variations in the weather, will also impact the bottom line.



Growth Rates: Sales Volume +/- 3%; Customers 2%; Operating Expenses 2%

FIGURE 2: Commodity Sales Impacts on Actual and Allowed Equity for Two Utilities

Figure 2 shows the asymmetric risk profiles of two utilities, one with increasing and the other with decreasing sales. Both are experiencing a 2% growth in the number of new customers and a 2% growth in expenses, while experiencing either a positive or negative 3% growth in sales respectively. A rate case occurs in year 6, bringing any deviations from the expected returns back to zero.

While the magnitude of these changes for a given utility may be higher or lower than assumed here, the relationships of earnings to sales, volume growth, customer growth and operating expense growth remains the same. The graph illustrates that small changes in sales, in this case 3%, can significantly affect the returns of each utility, both positively and negatively. By year five, the utility with increasing sales earns five percent greater revenues than expected, while the utility with decreasing sales sees losses of greater than 20% of expected revenues.

As a general rule, decoupling will have the effect of reducing the area defined by the curve (positive or negative) in both cases by essentially "truing-up" the utility's revenues. This explains the broader use of decoupling in the gas industry than in the electric industry, where it has the effect of providing earnings attrition relief. Similarly, it may explain why utilities with increasing sales trends, mostly electric utilities, may be reticent to give up these earnings windfalls by filing a new rate case or through decoupling.

FIGURE 2

The combination of the utility's cost structure and the method of pricing, such as net metering, can result in a strong incentive to avoid decreases in consumption and to embrace

[12] The average time between rate cases from 1984-1992 was 3 years. http://www.osti.gov/bridge/servlets/purl/10129186-0XkPRm/native/10129186.PDF

increases in consumption. This gives the utility the dual incentive to erect barriers to customer-side resources and to promote inefficient use of energy, whether explicitly apparent or not. This problem has been clearly identified for some time. As early as 1989, the National Association of Regulatory Utility Commissioners (NARUC) passed a resolution supporting regulatory changes that would make a utility's least cost course of action its most profitable one. Regulatory initiatives to implement this have been slow to emerge, but within the past year, a number of states have begun to address the issue.

The Role of Net Metering

For the photovoltaic industry, net metering represents the foundation of the U.S. solar market to date, and any discussion about decoupling and PV requires a clear understanding of net metering and its implications for utility disincentives. Net metering is currently available to at least some utility customers in 44 states (and the District of Columbia), most commonly for residential customers of investor-owned utilities, but the specificities vary significantly across states.

INTRODUCTION

Since the Public Utility Regulatory Policies Act of 1978 (PURPA), utilities have been required to purchase the output of Qualifying Facilities (QFs), the intent of which was to "encourage alternative sources of electricity beyond traditional generation facilities."[13] These QFs were originally envisioned as non-utility merchant plants that utilized renewable and/or non-renewable fuel sources.[14] The price paid for QF output was theoretically the "avoided cost" of the specific utility, a value that varied widely among utilities and among jurisdictions, both in the way it was calculated and the amount.

In cases where the utility had excess capacity or no near-term plans to build a new power plant, the avoided costs were often based on the short-run marginal cost of the utility – essentially avoided fuel costs and variable O&M, which might run as low as $0.02-0.04/kWh or less. In cases where the utility was still building or contracting for new power plants, avoided costs likely would have been based on long-run marginal costs, which would include some "capacity" value, and might run as high as $0.06-0.10/kWh or higher. In either case, the total avoided cost has been typically limited to the avoided or deferred generation costs and has not usually included any non-generation costs, and have been set at levels which are inadequate to encourage on-site generation from a customer's viewpoint.

Recognizing this limitation and seeking to expand the use of renewable technologies, most states have since adopted some form of net metering as another way to value the output of renewable energy and encourage its deployment. Utility customers, where applicable in a state, can offset their electricity consumption at retail rates by placing on-site generation on the customer side of the meter through net metering. Any short-term over- or under-generation relative to consumption is accounted for through the on-site metering and the billing accounting system over the "true-up" period – generally monthly or annually. Over-generation during true-up period, which depends on state or utility rules, may be compensated at retail or avoided cost rates, or in some cases is "given" to the utility. Compensation at one of these two lower rates is consistent with the notion that on-site generation should be sized to consumption and act as energy efficiency, rather than a competitive generator, over the billing or calendar cycle.

THE CUSTOMER PERSPECTIVE

Whether the PV system installation merely displaces a customer's consumption or generates excess energy that can be sold to the utility (or into a market), the economic value of the output of customer-side PV installations is largely defined by the utility's tariffs, i.e. the retail price for electricity.

Net metering treats on-site generation as if it were avoided consumption, allowing the retail offset of electricity, but also allows the customer to receive retail credit for short-term over-generation during a monthly or annual true-up period. With net metering, the customer's value for renewable output is equal to the full retail tariff paid for purchases from the utility, a price that can run as high as $0.35/kWh or more in parts of Hawaii and California. This value is almost always significantly higher than the avoided cost for a utility and is a major component of the economic equation for distributed generation. Customers can theoretically offset all, or nearly all, of their annual bill by generating their own electricity, although in most cases the PV system is sized to less than half the historical annual

[13] Congressional Research Service, Report RS20146, Available: www.ncseonline.org/nle/crs

[14] Non-renewable fuel sources were required to be either high efficiency cogeneration plants or utilize a fuel that was either a waste fuel or one with low market value.

consumption levels due to system spacing or economic limitations.

THE UTILITY PERSPECTIVE

From the utility's viewpoint, there is a significant difference between QF treatment and net metering. In the case of QF treatment, and especially if the avoided cost is at or near the short-run marginal cost of the utility, the net cost to purchase the QFs output is, at least theoretically, zero – revenues paid out to the QF equal the costs not incurred generating that much energy. In fact, because of the way recovery of energy costs like fuel are averaged in the ratemaking process, the utility might even make money on a QF transaction if it's actual avoided costs are higher than the official QF avoided cost rate.

Unlike avoided cost rates, which include only generation related costs, the retail price of a utility's tariff includes all of the underlying costs of serving customers, including return on equity – the utility's profits. Thus, with each kWh not sold the utility has given up some of its profit. In effect, net metering *maximizes* the lost profit impacts associated with renewable energy output. Like QFs, however, the utility may incur an even greater loss (or conversely a smaller gain) if actual avoided costs are, respectively, higher or lower than the average costs embedded in the tariff price.

The impact of net metering and customer-generation can have the effect of slightly higher rates for the utility's other customers. That is, a "wires-only" utility must recover its authorized revenue requirement over fewer sales because the customer-generation has reduced sales.

Net metering has practical limitations which prevent its use at high penetration levels. To take the extreme, if 99 of the 100 customers in a customer class all deployed net metering equal to their total annual energy needs, nearly the entire cost of service for the utility would be shifted to the 100th customer. Long before that, the utility profit requirements would, for practical and political purposes, come into direct conflict with acceptable retail prices.

U.S. and European PV Market Approaches
An alternative to the U.S. approach of utilizing net metering and one or more federal, state, or other incentives, the feed-in tariff is utilized significantly in Europe, but relatively rarely in the United States, though the policy debate is increasing.

Net metering is one of many incentives that a PV system can secure from a variety of different sources in the United States. A PV system will utilize net metering and perhaps a rebate or performance incentive from the utility, potentially a separate tax credit or incentive from state government, the federal investment tax credit, and if applicable, accelerated depreciation to create a positive rate of return (though smaller markets are often "ethics" driven rather than "economically" driven, i.e. environment or energy independence concerns). U.S. taxpayers, ratepayers, and utilities fund some part of the financial package to different degrees, which makes for a more robust, but complex system. No one incentive supports the entire foundation, and a shift in policy for one likely leaves the others substantially in place. However, there are transaction costs in utilizing multiple incentive sources, including paperwork, accounting or legal fees, unique business structures, and other resources necessary to implement a project.

In contrast, many European countries utilize feed-in tariffs (FIT), which can create a simpler methodology and clearer path for customers, utilities, and the industry, but are a more visible political target in the funding allocation process. Under a feed-in tariff, PV systems are interconnected on the utility side of the meter and paid a higher-than-retail payment for ten or more years. All electricity production is sent into the distribution grid and FITs have no direct relationship to the building's onsite energy consumption, so there is no impact on revenue for the utility. The FIT is generally above prevailing market electricity rates and requires funding from general taxes, electricity taxes, carbon taxes, or other sources, which can marginally increase electricity rates and reduce consumption. However, this is a price effect, not a direct impact from DG performance.

Under a FIT, PV can become a business investment with more predictable cash flows across utility service territories and geographies, depending on the scope. Minus the transaction costs associated with the U.S. approach, which may be significant, the end financial return to the customer can be similar. However, the single FIT can also be more clearly targeted for reductions or elimination during policy changes, such as might occur during an economic downturn or change in administration. As a result, each PV market structure has basic pros and cons.

CONCLUSION

While net metering's current impact on electricity sales is less than changes in population, macro economic conditions, or deviations from forecasted weather conditions, reduced electricity sales from net metering presents a clear disincentive to the utility over the long term as the photovoltaic market grows. To the extent one believes that distributed generation and advanced energy management represents a fundamental change in distribution-level electricity delivery over the long term, similar to the personal computer versus the mainframe computer or the cell phone to the wired phone, net metering represents a growing source of revenue loss over the medium to long-term.

Decoupling

INTRODUCTION

In order to remove the disincentive for customer-side resources, revenues (and therefore profits) can be decoupled from sales volume. That is, there are cost recovery and pricing techniques that can substantially avoid utility revenue *reductions* or *windfall* earnings that arise from changes in consumption from energy efficiency, net metering, weather, macroeconomic conditions, or other issues. As such there is both an upside for utilities (removal of risk from revenue loss) as well as society (removal of risk of paying for excessive returns).

Decoupling mechanisms introduce a process of recovering authorized revenues between rate cases and explicitly break the link between revenues and sales. While traditional regulation fixes prices between rates cases and allows revenues to change with changes in consumption, decoupling holds revenues constant (or provides a formula that sets the target revenue) and allows prices to change periodically (e.g. monthly) to collect the target revenue. As a general rule, the more frequently prices are adjusted, the smaller the magnitude of the adjustments. Because actual revenues collected more closely match those set in the rate case, revenue decoupling is more likely to keep the utility's revenue recovery closer to its actual cost of service than traditional regulation does and reduces, if not eliminates, over and under recovery from ratepayers.

Decoupling does represent a deviation from traditional regulation, and often faces institutional resistance from regulators, their staff, and residential and large consumer advocates. Much of this resistance is a function of preferring "the devil you know," rather than a fundamental opposition to decoupling itself. Some of it is based on misconceptions about what decoupling does and does not do. However, more and more states are addressing this resistance and are embracing some form of decoupling at least on a test basis.

It is important to understand that decoupling makes the utility theoretically indifferent to distributed resources by removing the throughput incentive, but it does not provide positive incentives for the utility to deploy DR. While it provides protection against utility revenue and profit erosion from DR, it does not turn DR into a profit opportunity, and works best when used in conjunction with other incentive structures that induce utilities to embrace economic DR.[15]

DETERMINING ALLOWED REVENUES

Decoupling has two fundamental mechanisms. First, there is some mechanism for determining the amount of revenues the utility should collect. Second, decoupling has a mechanism to set an appropriate price to collect the target revenue.

Revenue Cap Decoupling

With revenue cap decoupling, the target revenues are typically set in the rate case and then held constant until the next rate case. This approach is no longer in widespread use, if it is used at all.

Inflation and Productivity Decoupling

With Inflation and Productivity Decoupling, the target revenues are adjusted between rates, based on assumed or known changes in inflation and company productivity. Inflation is often based on a recognized government-published index, such as the consumer price index. Productivity is more often litigated in the rate case and serves to offset inflation over time.

Revenue Per Customer Decoupling

With Revenue Per Customer (RPC) Decoupling, the average revenue per customer for each volumetric rate is computed at the end of the rate case. In subsequent periods, target revenues are derived by multiplying the actual number of customers served by the RPC value. The underlying premise for RPC decoupling is that, between rate cases, a utility's underlying cost structure is driven primarily by changes in the number of customers served.

RPC decoupling begins with a traditional rate case and prices are set in the usual manner, using traditional rate design techniques. For each rate class, RPC values are calculated for each volumetric rate ($/kWh and $/kW) and for each month. While this calculation is not usually done in a traditional rate case, it is easily derived

[15] SEPA is currently working on phase two of a utility solar business models project, originally funded through a U.S. Department of Energy Solar America Initiative grant, which identifies business models that can incent proactive utility involvement in the solar industry itself. The phase one report is available for download from the SEPA website.

from data found in the reconciliation of a utility's prices to its revenue requirements as decided in the rate case, i.e. the tariff "compliance" filing. With the RPC calculations in hand, the allowed revenues for any post rate case billing period can be calculated by multiplying the RPC value by the number of customers.

RPC Decoupling Math

There are five basic steps in the RPC decoupling calculation:

1. Test Year Average RPC = Test Year Revenues ÷ # Customers
2. Allowed Revenues = # Customers x Test Year Average RPC
3. Actual Revenues = Units Sold x Current Tariff
4. Shortfall (or Overage) = Allowed Revenues – Actual Revenues
5. Decoupling Adjustment = Shortfall (or Overage) ÷ Billing Determinants

This is done for each rate class and for each volumetric rate and repeated periodically.

Advantages of RPC Decoupling

RPC decoupling has a number of advantages. First, it recognizes that a utility's underlying costs do change with the number of customers. This preserves growth potential for utilities and associates, while maintaining a relatively constant impact across all customers. Conversely, this also means that between rate cases, the revenue contribution of new customers goes toward sharing the cost of service, rather than flowing out to shareholders and the government, in the form of taxes on increased earnings, as in traditional regulation.

Second, between rate cases, RPC keeps a utility's revenue collection closer to its actual cost of service. Although RPC decoupling does not guarantee a given rate of return, it should keep the utility within fair shouting distance of their "approved" return levels.[16] This has the added benefit that each rate case is likely to generate less potential "rate shock," i.e. the requested and allowed increases in prices in each rate case are likely to be smaller since the retail price increases associated with RPC decoupling can occur more frequently.

Third, RPC decoupling is simple to implement and administer. Because all of the information necessary to implement RPC decoupling can be obtained from rate case "adjusted test year" information or from the company's billing and metering data, RPC decoupling has a low risk of litigation or disagreement.

Finally, RPC decoupling generally eliminates weather-related non-commodity revenue risks for both the utility and the customer. RPC decoupling is often mischaracterized as "shifting" the weather risk from the utility to the consumer. In fact, utilities and consumers either experience or avoid weather risk together, although with opposite economic effect. Under traditional regulation, utility rates are typically computed using weather-normalized data, but actual revenues are significantly affected by weather. In extreme weather years, consumption rises and therefore so do revenues and profits – at the expense of consumers. In mild weather years, consumption falls and therefore so do revenues and profits – to the benefit of consumers. Because RPC decoupling continually recalibrates allowed revenues using a weather-normalized RPC value, it has the effect of eliminating weather risk. Thus, neither extreme weather nor mild weather will drive revenues up or down.

Disadvantages of RPC Decoupling

RPC decoupling, while effective, is arguably not as "precise" as some forms of limited decoupling where decoupling is limited to utility-sponsored programs for energy efficiency or distributed generation (discussed below), assuming you can accurately measure lost revenues from specific causes. Because RPC decoupling determines prices and revenues at a class level, it may inadvertently compensate for revenue changes driven by activities other than DR that regulators would rather not include in the system. For example, reductions in consumption caused by an economic downturn would be compensated for in a decoupling mechanism. Of course, the same compensation would occur if a rate case were based on the same economic data because the utility is

[16] RPC Decoupling does not affect the ability of the regulator or consumer advocates to challenge utility expenditures on the basis of prudence or which do not meet the used and useful test. Such challenges can still be addressed in the utility's general rate cases.

entitled to collect its prudently incurred costs in its rates.

DETERMINING THE REVENUE EXCESS OR SHORTFALL

In terms of determining the revenue excess or shortfall, decoupling price adjustment mechanisms can be divided into three different types – limited, full and partial.[17]

1. Limited Decoupling - Prices are adjusted periodically based on the specific measured or presumed impact of one or more, but not all, of the factors, such as weather, energy efficiency, net metering, etc. that impact unit sales volumes. Usually limited decoupling is used when regulators want to limit the scope of decoupling to the specific impacts of, say, energy efficiency or distributed generation or to exclude specific impacts such as weather.

2. Full Decoupling – Prices are adjusted periodically based on total changes in sales, without regard to the specific causes for those changes. In this approach, regulators and stakeholders are usually seeking to a) avoid the accounting or analytical cost of attributing changes in sales to specific causes, b) reduce the total cost of service associated with decreasing the utility's risk profile, and c) provide maximum revenue protection for the utility.

3. Partial Decoupling – a variation on limited or full decoupling that limits the price adjustment to some portion, less than 100%, of revenues eligible for decoupling, most often expressed as a percentage, e.g. 90% of revenues. Partial decoupling is often used if regulators fear too much volatility in the decoupled prices or wish to continue to place the utility at-risk for some of the changes (without regard to cause) in sales.

Limited Decoupling

Limited decoupling limits the revenue recovery or credit amount to a limited set of specific causes such as energy efficiency and distributed generation, or energy efficiency but not weather, etc. It has most often been used to preserve weather risk for the utility and its customers by excluding the effects of weather in the decoupling calculation. Weather is the predominant cause of volatility in electric consumption. Weather risk is discussed in more detail below.

Depending on how the decoupling is being "limited," energy efficiency and/or net metering may need to be explicitly included in the calculation, using the utility, or possibly a third party, to conduct measurements or provide analysis to verify and track changes in sales due to the allowed or disallowed specific causes.

In the case of customer-owned solar PV, the specific cause of reduced revenues could theoretically be computed with great accuracy. However, within the context of net metering and photovoltaics, the specific measuring arrangement will vary considerably across states, utilities, and system sizes, with smaller systems less likely to have meters measuring total solar generation[18]. A revenue grade meter is not necessarily installed between the inverter and the house panel as common practice, so onsite consumption occurs before any electricity flows out through the meter at the point of common coupling. In these installations the net excess generation (NEG) is generally known, which is a measurement of any generation in excess of consumption over a billing cycle or annual accounting true-up, but not the total generation. While this is useful for the financial treatment of NEG, it doesn't accurately account for total lost revenues from the overall generation. For these systems an estimate of annual generation or a proxy average of similarly sized systems with metering capabilities could be utilized in place of an exact number from all installations.

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[17] See also Shirley, Wayne et al. "Revenue Decoupling – Standards and Criteria (A Report to the Minnesota Public Utilities Commission)," Regulatory Assistance Project. June 30, 2008.

[18] For smaller systems, meter costs and additional monthly fees can be a significant portion of solar revenues, and as a general policy simplicity is often substituted for accuracy. Most inverters keep track of total generation, but are not considered revenue grade meters, and have no automated utility collection method. In some cases, particularly larger systems, all or a subset of PV systems that have received a financial incentive, from the state or utility, may have total generation metering for program performance verification but there is no consistency across states.

Advantages of Limited Decoupling

The perceived advantage of limited decoupling is that it is designed to capture only the effects of specific causes of changes in sales. It has typically been used to include the effects of utility sponsored energy efficiency initiatives or to exclude the effects of weather. There is no reason it could not be applied to the revenue lost from customer-owned generation. Because customer-owned generation can be easily metered, the exact lost revenues from net lost revenue recovery can be easily calculated.

Thus, limited decoupling could be a good fit for customer-owned generation, if it were the only activity being measured or if it were being included as part of a broader decoupling mechanism. Because decoupling is typically also associated with energy efficiency initiatives, which are likely to have a greater impact on sales, the same mechanism a regulator deems appropriate for energy efficiency is likely, for ease of administration, to be extended to customer-owned generation, rather than having a different approach.

Disadvantages of Limited Decoupling

The principal drawback with limited decoupling is the need for, and cost of, additional and more sophisticated measuring and calculation systems necessary to track specific causes for changes in sales. When sales deviate from one year to the next, it is a complex task to interpret and calculate which specific factors caused the deviation and to what degree, e.g. how much was due to weather changes, economic downturn or growth, net metering, energy efficiency, etc.?

To derive sales impacts of specific causes requires a good deal of judgment, often supported with complex mathematical regressions or econometric models. Experience has shown that this can lead to increased litigation and increased regulatory costs

Full Decoupling

Full decoupling simply uses billing determinants from the company's metering and billing records to periodically adjust prices. This approach captures all factors that could increase or decrease sales.[19]

Advantages of Full Decoupling

Because full decoupling captures all changes in sales, it automatically captures all kinds of DR, including energy efficiency, demand-response, demand-side management, and all forms of customer-owned distributed generation. As a result, no separate accounting is required for the revenue effects of individual kinds of DR. This also maximizes the reduction in risk faced by both customers and utilities and the associated reduction in overall cost of service paid by customers, due to the lowered revenue risk for the utility.

Disadvantage of Full Decoupling

Consumer advocates and other stakeholders often express a concern over restoring revenue losses for causes other than specific utility-sponsored energy efficiency or renewable programs. Whether other causes, such as weather or economic conditions should be included or excluded is a regulatory judgment call. The trade-off of exposing the utility and its customers to greater risk is the increased cost of capital caused by increasing the utility's revenue risk – a cost ultimately paid by consumers.

APPLYING THE DECOUPLING PRICE ADJUSTMENT

Decoupling price adjustments are usually administered in one of two ways – through an accrual mechanism or with a current mechanism. In the accrual approach, the differences between actual and target revenues are tracked for some period, usually a year, and then collected or refunded over a subsequent

[19] California's Electric Revenue Adjustment Mechanism (ERAM) in place since the early 1980's (with the exception of the period of deregulation in the mid-1990's) is a form of full decoupling. The three investor-owned utilities in California file on a three year rate case cycle, where the target revenue is determined, with an adjustment for inflation, customer growth and capital expenditures in years 2 and 3. Generally, differences between the target revenue and actual revenues are tracked and refunded or recovered as appropriate in the following year. It should be noted that ERAM includes a number of performance-based, incentive mechanisms that are also part of the ERAM calculation. Due to its' complexities and specificities, which have evolved over time and which are important to California's success in decoupling, may not be particularly applicable to states seeking to implement decoupling currently.

period – usually the following year. The accrual method may be a pragmatic necessity with partial decoupling approaches because of the need to account for specific causes for changes in sales; however, it does cause a mismatch between the consumption levels that caused the adjustment and consumptions levels used to collect or refund the adjustment. There is also some turnover in the customer base so some customers may pay an additional amount or get a refund for consumption when they were not even customers and vice versa.

In the current approach, the utility applies the price adjustment on current bills and no accrual account is kept or required. The current approach can be used with full decoupling, because all of the information needed to calculate the decoupling adjustment, that is, the customers' billing information, is known at the time bills are prepared. There are no time-shifting issues associated with the current approach and no problem with customer turnover.

In all forms of decoupling, the ultimate prices are derived by dividing the allowed revenue by the actual consumption. The difference between the original tariff and the "new" price is the decoupling adjustment. In essence, the last steps of the rate case are repeated periodically to set new prices on a regular schedule, rather than every few years when an official rate case occurs.

Alternatives to Decoupling

These alternative methods attempt to either limit the revenue losses or compensate the utility for estimated or actual lost revenues, but do not explicitly break the "throughput disincentive" between revenues and sales.

1. **Net Metering Limitations** – particular to the photovoltaic industry, net metering limitations prescribe caps on factors that impact revenue loss from net metered customer generation
2. **Straight Fixed-Variable Rate Design (SFV)** – utilize high fixed charges to recover fixed costs
3. **Net Lost Revenue Adjustments (NLRA)** – similar to limited decoupling, as it is based on recovery of specific lost revenue variables, but it is implemented more like a fuel clause adjustment mechanism rather than a more comprehensive revenue targeting process as in decoupling
4. **Real Time Pricing** – utilize dynamic retail pricing to more closely reflect underlying utility cost structures
5. **More Frequent Rate Cases** – schedule rate cases on a more frequent basis to limit the time period of any over/under collections

NET METERING LIMITATIONS

Net metering has emerged over the last 25+ years as a public policy compromise between utilities, their customers, and as public policies to promote environmental and economic development goals. The differences among states have produced a complex patchwork of rules and regulations that have interpreted these competing interests to varying degrees. Indeed, one of the quick lessons that European solar companies learn about the US market is that it is really 50 different markets when it comes to understanding the various nuances of even one issue, such as net metering.

Four specific net metering characteristics that are common across states have emerged that act to limit revenue losses for utilities where net metering is available to customers.[20] As a result, net metering may only be available to certain customer classes, under certain individual installation size limits, for generation equal to or less than electricity consumption and/or within aggregated utility-wide limits:

- Customer Classes – Availability to residential customers is most common, but can also include or exclude educational, commercial, industrial, agricultural or governmental customer categories.
- Individual Size Limits – The maximum nameplate system capacity size of any individual installation is often defined by customer type, e.g. 10 kW for residential, 100 kW for commercial, etc. Fourteen states have limits of 1,000 kW or greater, with a notable increase in the ceilings for many states in the last few years.[21]
- Treatment of Excess Generation – On-site generation and consumption are generally not matched well with one another, i.e. on a daily, monthly and annual basis the two can differ significantly. Net metering accounts are generally "trued-up," that is the generation and consumption are netted on an accounting basis, over a monthly or yearly time-frame. Any generation that exceeds consumption during this balancing period is typically assigned a lesser monetary value.
- Aggregated Capacity Limits – Some states limit the amount of aggregated net metering capacity that can be installed within any one

[20] While these criteria impact revenue loss specifically, their original intent may or may not have been to target it explicitly. In addition, utility type (e.g. investor-owned, cooperative, municipal, etc) could also be considered a characteristic, although its impact on revenue loss is whether to utilize net metering for a particular set of utilities.

[21] The Energy Policy Act of 2005 requires states to review their net metering policies and make a determination on a standard by August 8, 2008. The net effect has been that a number of states either enacted a new or expanded net metering provision that may not have otherwise.

utility's service territory, either as a fixed amount of capacity in kilowatts, a percentage of the utility's peak demand in kilowatts[22], or a percentage of the utility's annual sales in kilowatt-hours[23].

These limitations may or may not have been implemented to specifically manage revenue loss, but their effect does so, while limiting the growth of the solar industry. While generally adequate for the residential markets, net metering limitations are having a definite impact on the commercial, industrial and institutional PV markets, especially with the maximum system size limitations. While even two or three years ago, a 1 MW PV system was "front page solar news," today it deserves mention, but is becoming common place with the advent of third-party solar developers working with internationally known corporations to develop strategic PV deployment strategies. As a result, prescriptive net metering limitations are beginning to hinder PV markets, even as public policies on renewable energy and carbon reduction goals are encouraging them.

STRAIGHT FIXED-VARIABLE RATE DESIGN (SFV)

A number of gas utilities have recently championed straight fixed-variable rate design (SFV). As a matter of rate design theory, SFV is premised on the notion that most of the utility's delivery system costs are fixed and therefore customers should pay for those costs through high fixed charges on their bills. Whereas the typical "residential customer charge" for a gas or electric utility may be around $5.00-$10.00 per month, this approach would increase that charge to a much higher level, perhaps as much as $40.00-$60.00 per month, while reducing the cost of the actual electricity or natural gas.

There is an intuitive attractiveness to SFV – if the costs are fixed, then it makes sense to collect those costs through a fixed charge. However, such fixed-cost intuition is misguided because in the *long-run*, most costs, not just fuel costs, are actually variable – system asset costs and debt service, operating and maintenance costs, customer care costs, and even some administrative and general costs. On a basic level, patterns of energy consumption drive the type of utility system built to serve that consumption. As we use more energy "on peak," for example, corresponding amounts of peak capacity must be built to serve that demand. Conversely, if we reduce on peak consumption or overall energy use, a different and likely less costly system could be built to serve that need.

One of the objectives of good utility rate design is to send a consumption price signal to the consumer. The SFV method with its lower variable rate serves to mask the marginal impact of consumption on long-term planning choices by replacing long-term cost-price signals with short-term "dispatch" price signals. Because the opportunities for customer savings are limited to the commodity, the consumers' economic choices will be based on the short-run commodity cost, rather than on the long-term cost of supply-side and demand-side resources.

The main advantage of utilizing SFV is the revenue certainty for the utility. The utility is assured recovery of its allowed revenues, although the same is true of decoupling. Customers will have lower variations in their monthly electric bill, which many consumers prefer for budgeting purposes, but at the cost of diminishing the value of customer-owned generation and energy efficiency.

While SFV does have the effect of decoupling the utility's earnings from consumption, it also has the effect of decoupling the customer's usage from the bill. Regardless of the customer's energy or demand, the bill will remain marginally unchanged. This reduces the value to the consumer of shifting or decreasing consumption, or encouraging distributed generation investments because the avoided energy rates are much lower. This significantly

[22] Typically there is no distinction between the direct-current solar nameplate capacity and the utility's alternating-current peak electricity demand in information discourse, which may be artificially limiting the amount of aggregated net metering capacity available in the few locations where these limits have been or are close to being met. Derating the solar capacity 80-85%, e.g. a 1 kW system is 0.8-0.85 kW to the grid, would be more technically correct assessment. Capacity limitations are likely related to technical grid penetration and operation concerns as much as revenue loss.

[23] Evaluating photovoltaic aggregation limits as a percentage of electricity sales would directly impact revenue concerns, and given the lower capacity factors relative to traditional generation, free up additional "space" within the aggregation limit, i.e. a 5% energy limit (kWh) would allow more PV than 5% capacity (kW) limit.

undermines the economics of DG and makes SFV a poor substitute for options without this disincentive.

Finally, SFV creates a high monthly fixed cost for residential customers, so the transition would produce a significant price increase for low use customers. This will be seen in two negative ways. First, it serves to penalize those who have invested in energy efficiency and minimized their consumption. Second, for lower income consumers who have reduced their use to fit a budget, the bill increase associated with SFV represents another obstacle to financial stability.

NET LOST REVENUE ADJUSTMENTS

Net Lost Revenue Adjustments (NLRA) are similar to limited decoupling, as they are based on recovery of lost revenues from specific causes. NLRAs typically use an accrual account which is deferred and then recovered in a subsequent rate case, or in a special net lost revenue case. The specific lost revenues are then allowed to be recovered as part of the overall cost of service.

The primary advantages of NRLA are similar to that of limited decoupling in that it identifies specific issues that reduce revenue and seeks to restore them as accurately as possible. Similarly the disadvantage of identifying the specific variables, accurately measuring or calculating their contribution to lost revenues, and the mathematical complexity of determining or allocating the degree of impact increases with the number of variables. More importantly, NRLA also does not explicitly break the disincentive link between reduced consumption and reduced revenues – the throughput incentive.

MORE FREQUENT RATE CASES

In theory, if a utility were able to file for and complete rate cases on a more frequent basis, it would serve to avoid the revenue erosion which decoupling cures. However, rate cases are extremely costly and usually cannot be completed in less than 6-12 months. Most in the regulatory community would not consider frequent rate cases to be a viable substitute for decoupling.

RPC Decoupling Case Study

In 2005, the Mid-Atlantic Distributed Resources Initiative (MADRI) addressed a number of regulatory issues surrounding DR. As part of that process, the MADRI participants developed a model rule for decoupling, which is a modified version of the decoupling mechanism approved by the Maryland Public Service Commission for Baltimore Gas & Electric's gas operations.

MADRI's geographic footprint matches that of the original PJM service area – Pennsylvania, New Jersey, Delaware, Maryland, and the District of Columbia. Utilities in this area all operate in a wholesale market environment and serve their customers through "wires only" companies. The principal "profit" operations of these utilities are limited to the distribution and customer services such as metering and billing.

For the most part, residential and small commercial customers are served through some form of standard offer service, with large customers often purchasing directly in the wholesale market or through third-party energy service providers. Although they are experiencing opposite trends in average customer sales, the underlying financial relationships of these "wires only" companies is very similar to that of the gas utilities. They both exhibit a high percentage of fixed costs in the costs structure and have limited variable costs that can be avoided when consumption declines.

MADRI CASE STUDY[24]

In considering decoupling, MADRI developed a case study which modeled the implementation of decoupling using rate case and billing information provided by PPL, the largest electric utility in Pennsylvania.[25] This case study provided important insights into the mechanics of RPC decoupling.

PPL provided the adjusted test year billing information for residential, small commercial, large commercial, and industry rate classes, which correlated to the data used to set its then-current tariffs. PPL also provided data for the year before and after the adjusted test year.

The PPL Case Study performed two separate analyses based on the PPL data. The first analysis was a "backcast" designed to show what the price adjustments would have been in the year following the rate case test period had RPC decoupling been in place. This backcast was separately calculated for each of the four rate classes being studied. It was also calculated separately for each month, using monthly billing information. Finally, the analysis is limited to the delivery costs of the system and did not include any commodity costs.

Figure 3 reflects the monthly revenue adjustments that decoupling would have made for the "small commercial" customer class as an example. In this case the total revenue adjustment for the twelve month analysis period would have been an overall reduction in revenues of approximately $1.6 million, i.e. the utility overcollected revenues relative to the target. This negative revenue adjustment represents an overall 2% reduction in revenues, and was most likely driven by weather forecast deviations than any other factor. The average change in demand prices for the twelve month analysis period was approximately -$0.07208/kW-month and for energy prices was -$0.00028/kWh, which represent 3% and1% decreases respectively. These magnitudes are relatively small and represent the hypothetical price decreases necessary to achieve the target revenue.

[24] The spreadsheet used for this case study is available on the SEPA (www.solarelectricpower.org) or RAP (www.raponline.org) websites.

[25] The MADRI PPL Case Study is available at http://www.raponline.org/madri/.

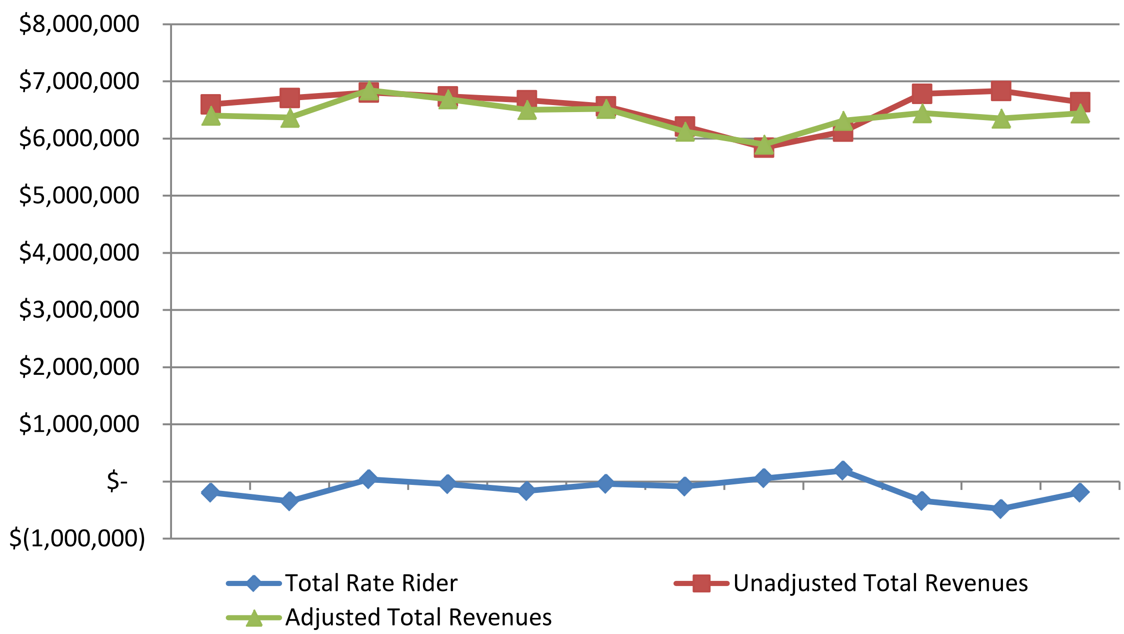


FIGURE 3: Total Revenues and Monthly Rate Rider Revenues

Of more interest is the second analysis done in the case study. In addition to the backcast analysis, the case study used adjusted test year information as a starting point and then forecast results for a three year period using growth rate assumptions for customers, DR penetration rates and base load versus peaking forms of DR. An additional variable modeled differences in the average consumption of new customers versus existing customers. The primary advantage of this analysis over the backcast analysis is that only the effects of DR are being captured in the analysis and abnormal weather is not present in the billing information. Table 1 reflects the results of this analysis, using a 1%/year penetration rate for a peak oriented reductions in sales and a 2% growth rate for the number of customers.

This case study is useful in two respects. First it demonstrates the application of decoupling to real-life data. Second, and perhaps more importantly, it provides a gauge for the impact of decoupling on prices. In each of the four rate classes, the overall impact on prices is seen to be minimal – certainly within the realm of political and practical acceptability as compared to fuel clause adjustment mechanisms. From Table 1, the revenue changes are small during the test period, with under collections of 0.23-1.16%, resulting in energy and demand price increases of 0.25% and 2.9% respectively.

TABLE 1: MADRI RPC Decoupling Forecast)

	Year 1	Year 2	Year 3
Revenue Change $	$146,000	$279,000	$896,000
Revenue Change (%)	+0.19%	+0.37%	+1.16%
Avg. Demand Price Change ($/kW-mo)	$0.00951	$0.01866	$0.05495
Avg. Energy Price Change ($/kWh)	$0.00002	$0.00004	$ 0.00006

MODIFIED MADRI CASE STUDY – IMPACT OF PV GROWTH[26]

The assumptions used for the previous case study are also appropriate when considering the effects of decoupling in the context of solar power, which reduces revenues in the same manner as energy efficiency or demand management would and which tend to be "on-peak" resources.

In a modified PV analysis using the MADRI case study, new PV is assumed to be deployed on a scale which is consistent with Pennsylvania's RPS requirements. For this analysis, a hypothetical "homogenized" rate class was constructed to reflect a total company average. Decoupling adjustments were then calculated for this total company profile.

Total revenue adjustments for the three year period were approximately $10 million, with most of the adjustment occurring in the energy charges. This is driven primarily by the large discount applied to the PV's coincidence with customer peak demand, which reduces the relative impact on demand charge revenues, relative to energy charge revenues. Total energy price changes are in the range of $0.00003/kWh-$0.00008/kWh, while demand price changes range from $0.002/kW to $0.006/kW (Figure 4). Using customer count and consumption information for PPL and assuming RPS consistent penetration levels, the average revenue and price adjustments are relatively small and certainly politically palatable – in the range of 0.18%-0.5% and 0.04%-0.12% increases in the "homogenized" overall rate class for energy and demand respectively.

Similar results are seen for the residential class alone, shown in Figure 5. Using customer count and consumption information for PPL and assuming RPS consistent PV penetration levels, the revenue and price adjustments are similarly small ranging from $0.0001/kWh to $0.00025/kWh, or approximately 0.56%-1.57% of retail prices used in the analysis.

Modified Case Study Assumptions

PPL
- Sales: 36.9 million MWh in 2005 increasing 3%/yr to 2018 [1]
- Default settings from previous MADRI case study

Solar Market in PPL Service Territory
- Solar RPS: 0.0013% in 2007 to 0.39% in 2018 [2]
- Timeframe: 2015 – 2017
- Installed PV Capacity: 83 MW in 2015 increasing to 141 MW by 2018
- PV Performance: 1184 kWh/kW/yr, prorated by month [3]
- Generating Capacity: 0% Jan-Mar, 96% Apr, 71% May, 54% Jun, 69% Jul, 69% Aug, 64% Sep, 29%, Oct, 0% Nov-Dec [4]

[1] U.S. EIA, State Electricity Profile (Pennsylvania), Table 3 – Top Five Providers of Retail Electricity, 2005; www.eia.doe.gov
[2] IREC, DSIRE, Pennsylvania Alternative Energy Portfolio Standard (reviewed 9/11/07); www.dsireusa.org
[3] PVWatts, Version 1 simulation for Allentown, PA; default settings
[4] Perez, Richard. State University of New York – Albany. Simulated Effective Load Carrying Capacity for Rochester Gas & Electric; 2% penetration, southwest orientation.

[26] The spreadsheet used for this case study is available on the SEPA (www.solarelectricpower.org) or RAP (www.raponline.org) websites.

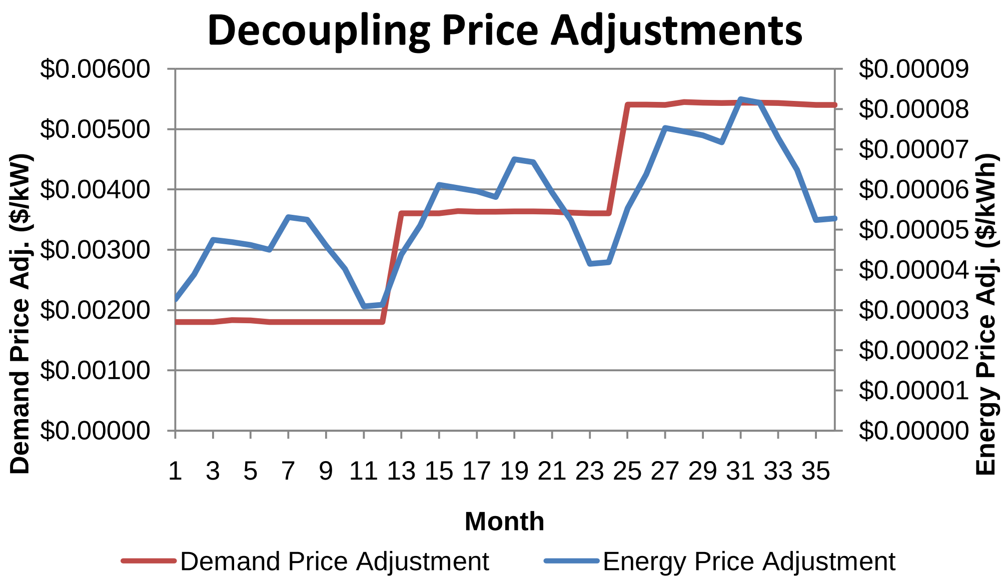


FIGURE 4: Energy and Demand Decoupling Price Adjustments – Total

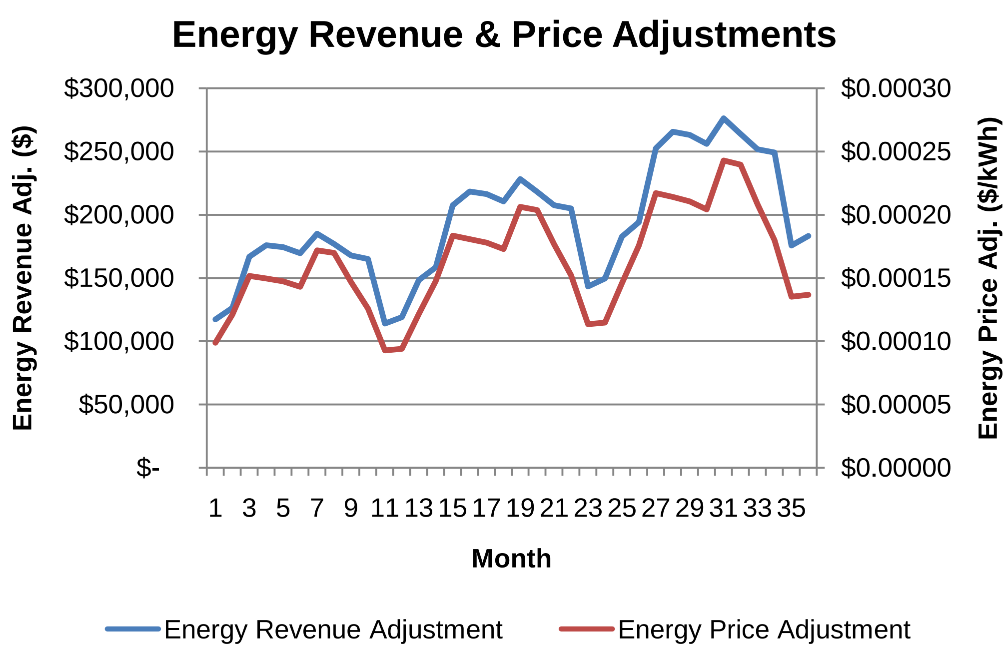


FIGURE 5: Energy and Revenue Decoupling Price Adjustments – Residential Only

Conclusion

All regulation presents utility managers with an incentive structure, explicit or not. Traditional cost-based ratemaking, which links revenues to sales volume, can put utility decisions at-odds with public policies favoring distributed resources, such as energy efficiency or distributed generation. While various strategies which exist to address the issue were outlined, many only compensate the revenue loss rather than fundamentally change the economic disincentive.

Decoupling can eliminate the disincentives that utilities face when customers deploy DR, such as solar PV, by clearly breaking the link between electricity sales and the amount of revenue recovered, while also sharing or eliminating upside and downside risks between the utility and ratepayers. Decoupling has been successfully utilized for more than 20 years in California. Other states are increasingly turning to decoupling as they pursue expanded efficiency and renewable initiatives.

The revenue-per-customer form of decoupling is the simplest to administer and has been gaining more traction in recent policy developments. The abbreviated MADRI case studies showed that the price fluctuations from RPC decoupling are relatively small and within the realm of other common cost adjustment mechanisms already in place within the regulatory environment.
It is important to remember, however, that decoupling does not create an immediate positive financial incentive for utilities to deploy DR. But removal of the throughput incentive, in whatever form it takes, can free the utility to pursue cost-effective resources without undermining their shareholder interests.

For More Information

National Association of Regulatory Utility Commissioners – *Decoupling Frequently Asked Questions*
http://www.naruc.org/Publications/NARUCDecouplingFAQ9_07.pdf

Massachusetts Technology Collaborative – Decoupling Resources
http://www.masstech.org/dg/decoupling.htm

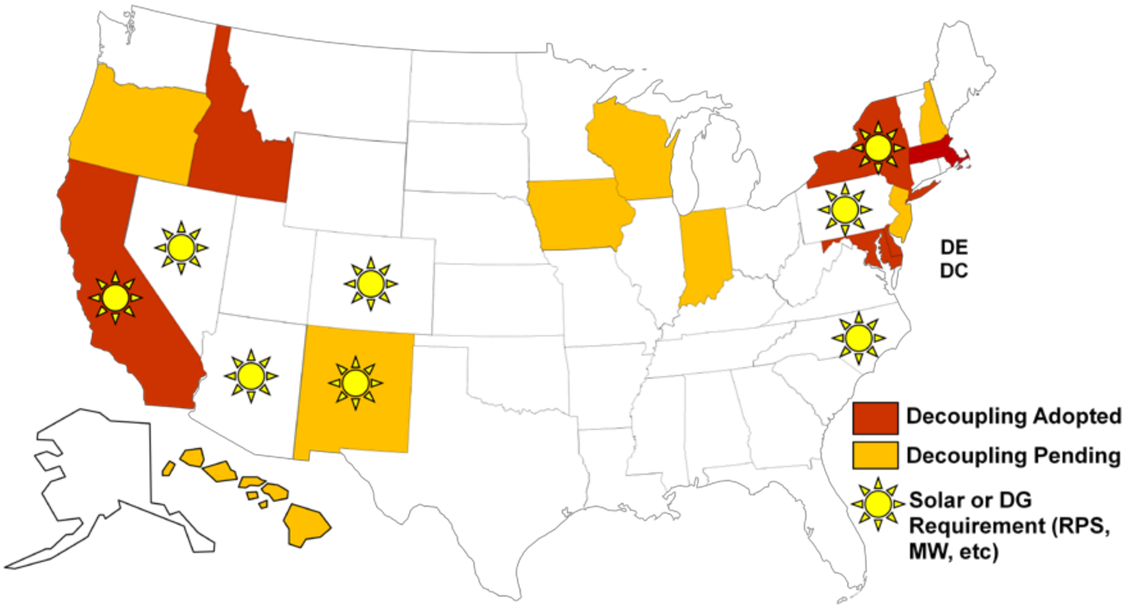
Regulatory Assistance Project
http://www.raponline.org

Solar Electric Power Association
http://www.solarelectricpower.org

U.S. Environmental Protection Agency – Energy Efficiency Action Plan
http://www.epa.gov/solar/actionplan/eeactionplan.htm

Appendix

December 2008



APPENDIX 1: State Electricity Decoupling and Solar Requirements Status

Sources (derived and adapted):
National Resources Defense Council "Electric Decoupling in the US" map, December 2008
Interstate Renewable Energy Council "Renewable Portfolio Standards" map, December 2008

SEPA Research Report Summaries

Residential Photovoltaic Metering & Interconnection Study (2008)
Utilizing data from a survey of 63 U.S. utilities, this report establishes a baseline of utility practices related to residential grid-connected solar photovoltaic metering and interconnection practices.

PV Capacity Methods (2008)
This report catalogues the statistical methods used to measure the relationship between peak electricity and solar PV output; compares all the methods in three case studies for three electric utilities; and documents the results from a 2007 workshop on the topic with utilities, industry and other stakeholders.

Utility Solar Business Models (2008)
While renewable market requirements are driving current solar investment, business opportunities are emerging for utilities to become involved in the solar value chain. This report highlights utility solar business models that provide value-added solutions for utilities, customers, and the solar industry.

Solar Fact Finding Mission to Germany: Report for Utility Decision Makers (2008)
Thirty-five US utility decision makers traveled with SEPA to Germany in June 2008 to examine how they can emulate the success of German utilities in integrating large quantities of solar electricity into a national utility grid without creating transmission bottlenecks, system quality distortions, or scheduling issues. This report summarizes the findings for other US utilities.

Top Ten Utility Solar Integration Rankings (2008)
In early 2008, SEPA conducted a nationwide survey of utilities to find out how much solar electricity was integrated into their service territories through the end of 2007. The resulting report, which will be repeated annually, crowns the most solar integrated utilities in the United States and discusses the number of announced solar projects to date.

Electric Utilities and Solar: A Market Review (2008)
This utility solar market report, which includes the solar integration rankings, discusses future solar market development issues that have arisen in 2007 and 2008, and their implications for utility involvement in solar.

Utility Solar Procurement (2009)
This report identified best practices for traditional utility solar procurement (RFPs/PPAs) and innovative new acquisition methods that may present cost or efficiency solutions for both utilities and the solar industry.

Utility Solar Tax Manual (2009)
In 2008, Congress extended the federal solar investment tax credit for eight years and removed the utility exemption, allowing regulated investor-owned utilities to utilize the credit. This manual provides detailed explanations of the tax provisions related to the bill, as well as exploring other tax issues such as Clean Renewable Energy Bonds, and unique business tax structures and issues.

Decoupling Utility Profits from Sales: Issues for the Photovoltaic Industry (2009)
The reduced sale of electricity creates an inherent problem for electric utilities in maintaining long-term operating revenue, especially as the solar industry expands. Decoupling is a regulatory policy option that can change the way utilities recover revenues to adjust this disincentive. This decoupling white paper introduces the concept into the solar community, explaining what decoupling is, and defining the different types. It includes a case study showing how solar market development in the future might affect utility rates under decoupling.

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