THE STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION
Docket DE 16-576

Development of New Alternative Net Metering Tariffs and/or Other Regulatory Mechanisms and Tariffs for Customer-Generators

Comments of Pentti J. Aalto on Value of DER Study
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A study of the value of distributed generation and other customer response possibilities is valuable at several levels. At the policy level we can review societal values such as environment, employment, national security and other effects that would be generally considered an externality in a market. A market on the other hand, works well to establish simple economic price and value. If the market is not satisfying societal needs we can provide steering signals through subsidy and taxes. In the case of renewable distributed generation we have provided subsidies to support investment but we have not been clear about market design.

In the early years of PURPA the concept of "avoided cost" led to a great deal of consternation. The issues at the wholesale generation level were addressed and resolved by the creation of a market. In the case of distributed retail generation "net metering" was adopted. The problem with net metering is that the existing utility infrastructure does not behave as a market and therefore, price and value discovery are confused. I believe that if we can develop a pricing structure that more closely resembles market pricing for utility services, we may be able to better address the issues of revenue loss and proper valuation of distributed generation and for that matter energy efficiency.

The basic principle is that in a transparent retail clearing market, price and value are the same.

I propose a load weighted pricing structure for utility delivery services that emulates a market. The task at hand is to evaluate the granularity of data that is available in real time from various parts of the system and to establish the cost of making that data available where it isn't.

Toward this end, I propose that our consultant evaluate the concept presented here and the availability of the information that would be needed to make it work.

Discussion follows:

The effect on the grid of a kWh saved by a customer is a reduction in upstream loading of generation, transmission and distribution. Downstream load is not affected. The effect of a generated kWh is exactly the same. The utility can't tell the difference. In the case of the saved kWh the customer does not pay for services the utility does not provide. In the case of the customer-generated kWh, a downstream neighbor uses the power and pays the utility full retail price for services the utility did not provide. If the utility credits the generating customer at the full retail value, the net effect on the utility is exactly the same as for the saved kilowatt hour, lost revenue. The potential cost-shifting effects are exactly the same for both. In a rate-base regulated wires services industry, prices will tend to rise if the revenue loss is greater than depreciation and cost reduction. From the customer's perspective, any increase would be balanced by cost reductions from increased competition and the resulting price pressure in the generating sector.

If the retail costs of energy and its delivery continue to rise, we may begin to see customer defection. Technologies for distributed generation and storage have been experiencing dramatic reductions in cost. Customers may begin to go off grid.

We may be able to avoid a potential death spiral if we can find ways to reduce existing costs and to increase the use of our existing infrastructure without adding new expense. The development of energy-efficient technologies that provide "beneficial electrification" such as electric cars and heat pumps for space heating and domestic hot water may give us that opportunity if we can limit their use at times that would require reinforcement of the existing delivery system. Today's flat kWh and non-coincident demand charges for residential and commercial customers however do not provide price signals to support these changes.

A pricing structure for distribution and transmission service that resembles a competitive market will provide price signals that more appropriately reflect the value of both generated and purchased power. The market price for services from a fixed asset with no short-term marginal cost varies based on utilization. At zero utilization, the price is zero. At high use, the price tends toward full congestion and an infinite price. The price curve that connects these points has the familiar hockey stick character, the price rises slowly as load increases and then rises rapidly with congestion. Since we do not have a competitive market for these services, we need to develop a proxy for a real market price. I propose that we work toward a real time price adder for each major segment of the transmission and distribution system, which would recover the cost of each segment and would present a price based on loading to be added in series to the customer's total price. The price curve for the segments would probably be best developed using the probability of peak method, however a good proxy can be developed using a simple algorithm such as a tangent function. This function would provide a load-based multiplier for a price that would provide the revenue requirement for that segment.

To explore these issues, I constructed a worksheet based on hourly substation loading data from the New England ISO for New Hampshire substation Webster for one year from February 2017 through January 2018. I assumed that substation and downstream feeder costs were being met at $40.00 a megawatt-hour to give a total revenue requirement. The data show a 37 MW peak so I assumed a 40 MW capacity. I assumed a second substation that had exactly the same load with a 50 MW capacity. The alternative pricing plans would have to be scaled to provide the same revenue total. The heavily-loaded substation however, would earn more than the lightly-loaded one. The heavily-loaded substation would tend to favor the development of distributed generation, storage and load reduction; while the lightly-loaded one would tend to favor increased development of beneficial electrification.

The price per megawatt-hour in each hour would be the tangent of the load as a percentage of the substation capacity times 0.9 (to convert to degrees) times the derived revenue scaling factor ($37.55/MWh) that applies to both substations.

Customer hourly delivery charges $/MWh=(TAN (load (MW)/capacity (MW)*100*.9))*
(derived revenue scaling factor $MWh)

The revenue scaling factor is derived by dividing the total revenue requirement by the total of hourly tangent adjusted megawatt-hours for both substations.

The results are as follows:
At $40.00 a megawatt-hour the revenue for the substation is $7,223,440.
Two substations with the same load would be $14,446,880.
Under the new model at $37.55 times the hourly tangent factor, the 40 MW more heavily-loaded substation has an income of$8,663,362. The lightly-loaded 50 MW substation has an income of$5,783,518 for a total of $14,446,880.

The charts that follow at the end present the load-duration curves for Webster station and the load price curves for the 40 and 50 MW pair of substations assumed in our example. The worksheet is available as an Excel file.

In the example above, we apply our load scaling factor to the substation and all connected feeders as a whole. In practice, a factor would apply to the substation only and separate factors would be developed for each connected feeder; further factors might be developed at significant points along the feeder. The practical application of this concept will require real time monitoring of each segment that we choose to define. The conventional primary voltage metering used with large customers would be adequate for this purpose when combined with communication that would allow for the assembly of the various prices that would add up for the individual customer.

In addition, the customer would require a control system and communication that would allow automated response to the price signal. At this time it is probably not appropriate to apply this type of pricing to customers that do not have the ability to respond. We have over 100 years of experience where customer response was not expected or desired. The cost to a standard customer of this type of pricing would probably be very similar to what they pay now, when considered over a longer term. However, month to month volatility would be viewed as extreme.

It should be clear that access to a market price is not necessarily in the interest of the distributed generator or for that matter the customer using a heat pump. Prices are not fixed and will vary a great deal. For example, if a substantial amount of solar is developed, day time prices for electricity would be depressed, thus reducing savings that might have been expected. Today's fixed prices are based on an average diversified customer mix. Heat pumps use more power during periods when the cost is high, but pay prices based on conventional customers. Over time, the use of more efficient market pricing will tend to foster the development of responses that will improve utilization of our existing investment and dramatically reduce cost.

In summary, this type of approach would provide more appropriate pricing signals to both customer load and generation. It would also simultaneously provide for the mitigation of potential lost revenue.

While markets do not handle externality very well, an open transparent retail market can provide simple economic price discovery and simultaneously value discovery. In such a clearing market, price and value are the same. Price is bidirectional, it is the same for both buying and selling.