Draft – Smart Rate Design for Distributed Energy Resources Report, Regulatory Assistance Project, for the Michigan Public Service Commission

Comments of 5 Lakes Energy

Summary

The draft report provides three DER rate design reform pathways: (1) Gradual Evolution Pathway; (2) Advanced Residential Rate Design for DER Pathway; and (3) Customer Options and Stability Pathway. Pathways (2) and (3) pose risk to subsidies by other customers and do not meet the cost of service principles of Michigan Law. If adopted, either of these sets of recommendations would result in harm to residential DER programs offered by Michigan regulated utilities and take a major step backward from the progress made in implementation of 2016 PA 341, and its mandate for a cost based DER pricing structure.

With respect to PA 341, the Commission, in compliance with the Statute, and after extensive analysis and stakeholder input, found that the Inflow/Outflow pricing model was a superior cost-based framework over net energy metering (NEM) or buy-all credit-all pricing models. It should be noted that the Commission found that the Inflow/Outflow pricing model is not a be-all end-all as initially implemented, but as metering and implementation data is gathered it would be a foundation for future innovations/improvements in linking cost causation with pricing under the model. No such data analysis was provided in the draft report, in particular, no metering or implementation data that indicates a need to completely reverse direction as recommended in the report. However, there are elements addressed within the report that may have merit, and these could be considered by the Commission in future general rate proceedings. It is possible that the Gradual Evolution Pathway could be modified to include these if further developed, while excluding those components/recommendations that are inappropriate.

Considering the significant change to DER pricing brought about by 2016 PA 341, a <u>gradual evolution pathway is the most logical future pathway for Michigan</u>, as it would provide the necessary time for data development under the new Inflow/Outflow framework, avoid customer confusion, provide the best opportunities to incorporate DER into decarbonization policies, promote new DER technologies, and protect the interests of residential customers of Michigan's regulated utilities.

The Gradual Evolution Pathway could form the basis for future policy direction. In particular, the draft Report is on target with its recommendation (contained in the Gradual Evolution Pathway) to improve future rate design through enhanced time-based rate schedules for which <u>both</u> power supply and distribution cost-components are time varying. Enhanced time varying rates for all customer classes would improve pricing signals and better connect rates with cause causation. A gradual evolution in this direction appears to be a reasonable pathway.

The Gradual Evolution Pathway, as formulated in the draft report, unfortunately contains a recommendation to move certain costs associated with "site infrastructure" out of residential kWh rates and into a tiered customer charge. Site infrastructure is defined as secondary voltage lines, distribution transformers, and service lines. Tiers are defined as (1) multi-family; (2) single family buildings with panel sizes of 200 amps or lower, and (3) single family buildings with panel sizes greater than 200 amps. The draft report's stated focus in on DER, and policy directions improving rate design with cost causation, but the tiered customer charge is in conflict with the physical realities associated having on

site generation. For example, a large residential customer with a panel size greater than 200 amps, may be a “net zero” customer (net zero on an annual basis), with coupled solar PV and battery storage. Power inflows are significantly reduced from such a customer, yet by linking customer-charge tiers to the size of the building’s service-panel, the proposal would effectively tie assumed grid usage to consumption, which is not true for DER customers. As an alternative approach to improve the connection between cost causation and retail rates (that recognizes distinctions between DER and full requirements customers), the Commission could consider a long-term goal of separating DG customers into their own cost-of-service customer classes. Clearly, such analysis will require solid data emanating from implementation of existing DG programs.

DER Pricing Models (#2 Advanced Residential Pathway and #3 Customer Options and Stability Pathway)

Significantly, the RAP Report recommends, in the Advanced Pathway, and in the Customer Options and Stability Pathway, to abandon the Inflow/Outflow pricing model. In the Advanced Pathway, abandonment of the Inflow/Outflow mechanism is based on the implementation of two new and flawed rate mechanisms, each of which is combined with a return to a limited form of net energy metering, typically called “net billing” in which excess power outflows (beyond the level of inflows during the netting period) are monetized. The two new rate mechanisms are: (1) a non-coincident peak (NCP) demand charge designed to recover allocated costs of “site infrastructure”, i.e., service lines, secondary voltage lines, and line transformers. (2) a “distribution flow charge” applied to both net excess inflows and to net excess outflows designed to primarily recover distribution system costs, but also nonbypassable charges such as the Energy Waste Recovery (EWR) surcharge, and A&G costs. The combination of a limited net energy metering, (i.e. net billing with kWh netting within pricing periods), and the two new rate mechanisms will create irreparable harm to the residential DG program.

Regarding the first of these two new charges, the logic behind eliminating the Inflow/Outflow pricing mechanism for residential DG customers on the basis of adding a new non-coincident peak (NCP) demand charge to residential TOU rate schedules is inherently flawed. Adding a demand charge is not a valid basis for reversing the major improvement in linking cost causation with DG rate design provided by the Inflow/Outflow pricing model. The Inflow/Outflow pricing model is highly robust in its ability to accommodate differing or new innovations in rate design associated with the underlying retail rate schedules of DG customers. If the Commission agreed (hypothetically) with the proposed residential NCP demand charge proposed in the draft report, such demand charge could be easily accommodated by the Inflow/Outflow pricing model without the need to outright abandon such DER pricing model. For example, all demand-based rate schedules for commercial and industrial electric customers of DTE and Consumers Power already qualify for the Inflow/Outflow DG rider. Importantly, adding a demand charge to residential rates may be inconsistent with a strategic move to enhanced time varying rate-schedules, so that despite the fact that the Inflow/Outflow pricing model can accommodate residential demand charges, the new demand charges is dubious as an evolutionary pathway for residential DER customers.

Regarding the second proposed new charge, the bi-directional distribution charge concept is flawed in concept; cannot cure the core subsidy issues intrinsic to net energy metering; and worsens the economic case for residential customers adopting DER technologies. It can be demonstrated that the proposal to combine a bidirectional distribution charge with the proposed net billing recommendation is averse to the stated objectives of better linking cost causation with rate design, and the creation of clear and appropriate pricing signals that will promote the increased adoption of new and renewable technology approaches.

Explanation of Why the distribution flow charge is flawed

The core subsidy issue associated with all variations of NEM (including the draft report's proposals) is that for every kWh of inflow netted with a kWh of power outflow (e.g., from a previous or future time increment within the pricing period), the utility forfeits the distribution and transmission charges on such power inflows (kWh netting results in zero utility revenue). The reason for this is that the physical delivery of a kwh of power inflow, irrespective of whether it is netted, requires full grid support, as netting does not remove the requirement for the utility to use its entire grid assets to deliver such kWh to the customer. In other words, from a cost causation perspective, netted power inflows (under the draft report's proposed NEM mechanisms) are indistinguishable from excess power inflows (for which the report acknowledges the need for recovering distribution costs), or for that matter, from power inflows from a full-requirements retail customer.

The lost revenue issue, e.g., under the draft report's proposed NEM mechanism, (with kWh netting within pricing periods) could be fixed by applying [charging the DG customer] the full distribution charge, plus the transmission component of the power supply charge, to all power outflows that are netted with power inflows on a kWh basis. In fact, doing so would create an equivalent bill as under the cost-based Inflow/Outflow pricing model. Clearly, the draft report's proposal to combine NEM with a grid distribution charge applied to <u>excess</u> power outflows (i.e. power outflows in excess of inflows) misses the boat completely with respect to obviating the core subsidy issue with NEM. It is not the power outflows in excess of power inflows during a given time increment that require a distribution charge, but rather the power outflows that were netted against the power inflows. The bottom line is that adding a distribution flow charge to power outflows in excess of power inflows (as proposed by RAP) does not remove the core subsidy of NEM that PA 341 requires in its mandated move to cost-based DG rate structure, but rather creates a significant distortion in reflecting cost causation.

An additional problem with having a "distribution flow charge" applied to power outflows in excess of kWh netted inflows, relates to the presumed policy basis for the charge. The draft report asserts that the DER customer "*needs the grid when the DER customer is in an exporting condition and thus pays a charge when feeding power to the grid.*" This argument can be reframed as the idea that a DER customer who injects power into the grid should contribute toward the cost of the grid because they cannot outflow without the grid.

Assuming such policy argument was valid, then the "distribution flow charge" under the RAP proposal should be applied to all power outflows as they occur, not just the cumulative amount that was in excess of cumulative power inflows at the end of a pricing period. This outcome would effectively nullify kWh netting within pricing periods. Logically, all forms of NEM, including the proposed netting on a pricing period basis, with a cash-out of excess power inflows or outflows, cannot exist, if the draft reports policy basis for a distribution flow charge was valid. The proposed "distribution flow charge" should not be incorporated into the final recomendations.

In context of DG customer outflows that are always small compared to power flows on the adjacent distribution lines, the outflows from DGE customers are not causing distribution system costs but instead are lessening power flows from upstream in the transmission and distribution system and leaving power flows downstream of the DG customer unchanged. Aside from the reverse flow from the DG customer to the point where that power flow combines with that of neighboring customers, this is precisely the same change in distribution system power flows that would result from reduced energy consumption due to energy efficiency measures, business operations changes, or household composition changes. A "distribution flow charge" is not consistent with the conception of cost causation used in all other aspects of Michigan utility regulation.

The fallacy of the "distribution flow charge" argument can also be seen by considering any seller of power into the electric grid. For instance, a PURPA seller of distributed power (i.e., interconnected with the distribution grid) also cannot transact with a utility without existence of the distribution grid. Charging PURPA distributed generation sellers a "distribution flow charge" would ruin an important source of clean energy and severely impact Michigan goals toward decarbonization. Clearly, the customers (i.e., retail customers) should pay for the grid (on the basis of their power inflows), not sellers, and not DG customers who outflow into the grid in order to obtain credits toward their utility bills.

Time Varying Rates

With respect to time varying rates, the Advanced Residential Rate Design Pathway, as proposed in the draft report, falls somewhat short of meaningful potential innovation, in that it is limited to pricing structures already in place. That structure consists of three TOU periods (e.g. on-peak, mid-peak, off-peak) set on a seasonal basis. Consumers Energy Electric already has implemented a three-period TOU pricing structure for its residential tariffs. DTE Electric is moving in this direction, but not yet to the extent of Consumers Energy. Under the currently approved Inflow/Outflow compensation approach, DG customer power outflows are compensated at the underlying power supply rate, less transmission. As a result, DG power outflows would automatically have a time varying characteristic for customers on the proposed default (underlying) multi-period TOU tariff. This is a positive result for improving price signals from flat rates. On the other hand, distribution costs are not fully allocated on a time varying basis at the present time. The draft report's recommendation to put all power supply <u>and</u> distribution costs on a time varying basis is sound and should be implemented on a gradual evolutionary pathway.

Both CE and DTE have an optional critical-peak pricing rate schedule for residential customers. Pursuant to the draft report, residential customers having DG, EV's, energy storage, or higher than 75th percentile in usage levels would be required to be on the multi-period TOU tariff, which also has a critical-peak rate component for months experiencing resource adequacy issues.

It is agreed, that as a near term step, a multi-period TOU tariff should be the default tariff for all residential customers of regulated electric utilities, not just those with DER characteristics. However, critical peak pricing should not be a default requirement, at this time, for residential DER customers.

Regarding time based pricing, the upshot is that the draft report is on target with its recommendation to improve future residential rate design through enhanced time-based rate schedules for which both power supply and distribution cost-components are time variant. [The move to enhanced time-varying rates for both power supply and distribution is included in the Gradual Evolution Pathway.

Additional Comments

The report contains secondary recommendations, one of which relates to expanding the creation of community solar projects. It is acknowledged that legal and regulatory constraints in Michigan prohibiting “virtual net metering” for community solar projects are harmful to the interests of low-income electric customers, such customers being essentially locked out of the current DG programs due to the high capital cost of solar PV, and due the high proportion of renters among low-income customers. Although the current DG programs have phased out NEM for new enrollments, the concept of “virtual” NEM may be appropriate for community solar projects as it would create energy justice for low-income customers. It is recommended that further exploration of this issue be taken.

“Virtual” net metering also has merit for rooftop solar in multiple-occupancy buildings. Using the common roof of an apartment building for solar that is shared amongst the occupants of the building has the same cost causation characteristics as single-customer DG customers but cannot access the same benefits for behind-the-meter generation as single-customer DG.

The “buy-all credit-all” proposal contained as Option A in Pathway #3, is not workable from a “rates follow cost-causation” perspective. The buy-all credit-all scheme has zero connection with what is physically happening at the interconnection of the DER customer and the distribution grid (at the customer’s meter). The “buy-all credit-all” pricing model is completely indifferent to inducing operational efficiency, i.e., the maximization of the level and timing of onsite generation to meet site load. Participating customers are required to pay full retail rates for imputed retail load that was physically served by the customer’s onsite generation. This creates a significant misdirection in pricing signals. In addition, the credit for generation under this pricing scheme has been historically set (at a subsidized rate) in the early years of distributed solar PV markets as a means to accelerate adoption of what, at the time, were very high costs of adoption. Under this approach DG customers loose the benefit of effective full retail-rate compensation for meeting load with locally generated power, and thus high and likely subsidized rates for generation would be required to induce customer enrollment. The draft report suggests a value of solar pricing for residential solar generation, containing externalities as part of the value stack. This presents significant regulatory constraints, to the extent that utilities do not actually incur such costs.

Lastly, the draft report’s recommendation pursuant to the Advanced Pathway, that rates be set on a marginal-cost basis may have merit, but this issue should be carefully studied by the Commission prior to any decision to implement. A new stakeholder workgroup to explore marginal cost of service methods, impact and implementation details would be a reasonable first step.