The analysis, views and recommendations in this presentation are those of the presenter and not necessarily those of MidAmerican Energy Holdings Company and its subsidiaries.
• Regulated utilities have managed reductions in the rate of electric consumption previously. Causes included increased appliance efficiency, energy efficiency programs, economic downturn, & voluntary conservation.

• Absent material customer movement completely off the grid (e.g., cost-effective residential electric storage; ability of industrials to lock in long-term natural gas at very low & predictable prices), previously utilized regulatory mechanisms will probably be adequate to deal with electric consumption reductions:
  – Decreasing the amount of distribution & customer service fixed costs in the variable component of rates & instead including those costs in the customer charge component;
  – Use of forecast sales in setting rates;
  – Attrition adjustments;
  – Risk adjustments to allowed ROE;
  – Decoupling for the unbundled distribution function.
Increased appliance efficiency, energy efficiency programs, economic conditions, & voluntary conservation are currently reducing electric consumption & utility sales. However, two different and increasing developments are reducing electric sales but not necessarily electric consumption.

Industrial customers are reducing energy purchases from the utility (but not necessarily electric consumption) by taking advantage of natural gas prices to generate their own electricity. This development can probably be adequately addressed by ensuring that:

- Partial requirements/standby tariffs reflect the full costs of that service;
- Regulatory policies regarding return to full requirements service recognize the cost to other customers of maintaining reserves.
Residential customers are reducing energy purchases from the utility (but not necessarily electric consumption) by use of DG.

- This development cannot be adequately addressed by partial requirements tariffs since those tariffs do not contemplate sales to the utility.
- This development certainly cannot be addressed by continuing to allow DG customers to be served under residential tariffs designed for the average full requirements residential customer because the latter has a different load profile & different cost of service.

Particularly if the regulatory & societal objective is that DG production will be integrated into the grid & serve other customers, new regulatory policies and new rate designs are critical.
• DG is a supply option; net metering (NEM) is a rate scheme. The issues between the two differ.

• A “smart grid” requires (a) smart prices for utility sales to retail customers, including DG customers; (b) smart prices for utility purchases of energy, including purchases from DG customers; and (c) smart regulatory & consumer policies regarding DG’s place in the grid.

• If a regulatory and societal objective is to integrate DG into the grid in a manner that provides maximum value to the grid and the customers it serves, then consumers and participants must be provided the tools and prices designed to achieve that objective. Merely tweaking traditional rate design and regulation will not be sufficient.
While the majority of residential DG customers are on NEM, not all are. For ratemaking and rate design, the following are pertinent to the DG customer not using net metering:

– The residential DG customer continues to use the utility system, but purchases fewer kWh in the billing cycle.
– Total electric consumption by the DG customer may remain unchanged.
– Absent net metering, all kWh usage of the utility system by the DG customer is metered, and all kWh used are currently billed at a residential rate. That residential rate was designed for a full requirements customer without generation and with a different load pattern & cost of service.
The DG customer’s reduction in kWh usage does not reduce the short-term fixed costs of serving the DG customer.

The DG customer’s peak energy production is unlikely to be coincident with the utility’s system peak, in part because the utility’s rates for system sales do not incentivize it.

To the extent the DG customer’s demand for utility system power at the time of utility system peak is unchanged by the DG (e.g., DG production is not coincident with utility system peak), the cost of serving (and standing ready to serve) the DG customer’s demand is not reduced.
- System peak loads in the West occur after 6:00 p.m. (blue)
- Market prices are highest during system peak (green)
- Solar and wind peak production is not coincident with either peak load or peak prices (red)

The graph depicts the timing of the maximum of the curves, not the absolute amounts

*July monthly averages
Solar Production on Simulated System Peak Day

- Scenario 1 (41.5° Tilt, 180° Azimuth)
- Scenario 2 (18.1° Tilt, 225° Azimuth)
- Scenario 3 (41.5° Tilt, 255° Azimuth)

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– To the extent two-part residential rate design includes any fixed costs and demand costs for distribution, transmission and generation in the kWh charges, the DG customer will not pay those fixed and demand related costs for the kWh it no longer purchases.

– To the extent the two-part residential rate design is inverted with multiple blocks, DG alone may be sufficient to enable the DG customer to avoid the tail block of the retail electric rate.

– To the extent the billing determinants used in setting residential rates included the kWh no longer purchased by the DG customer, until rates are reset that portion of the fixed and demand-related costs will not be paid by any customer. Following the next resetting of rates, those fixed and demand-related costs will be reallocated in the residential rate.
The last point would also be true for any residential customer that doesn’t have DG but permanently reduces usage for any reason; e.g., energy efficiency, life style, economy, demand response.

However, because the DG customer hasn’t simply reduced usage but is instead generating a portion of its energy, the DG customer uses the system differently than the average full requirements residential customer, places different demands on the system, and has a cost of service that differs from the average full requirements residential customer.

Applying the non-time-differentiated, two-part residential rate design developed for the average full requirements residential customer to a DG customer fails to provide any incentive to the DG customer to maximize production coincident with the utility system and circuit peaks, and fails to discourage the DG customer from creating needle peaks on the utility system.
Typical Residential Loads
Summer Peak Day

Residential

Daily kWh: 45.7
Load Factor: 63%

Residential with Solar DG

Daily kWh: 25.7
Load Factor: 40%
Typical Residential Loads
Average Day

Residential

Residential with Solar DG

Daily kWh: 27.2
Load Factor: 76%

Daily kWh: 13.0
Load Factor: 37%
NEM Issues Background

- NEM is not a method to enable the DG customer to “sell” excess production to a utility. It is instead a rate scheme that allows a DG customer to use the utility as an uncompensated “bank” for DG production during the billing cycle (or subsequent billing cycles, if credit rolling is permitted).
  - NEM is particularly inappropriate in a smart grid world as its value to the NEM customer is based upon inappropriate incentives, incorrect value assumptions and utilization of a rate design never intended for utility purchases.
  - NEM reduces kWh billing units by allowing the NEM customer to bank DG production during the billing cycle that exceeds the customers real-time kWh usage and then use the banked kWh to “erase” kWh purchases elsewhere (either before or after actual DG production) in the billing cycle.
  - Two-part residential rate design when applied to an NEM customer has all the infirmities applicable to DG customers in general plus it incentivizes the NEM customer to maximize total DG production during the billing cycle without regard to the value to the system of that production.
  - NEM also is founded upon the incorrect assumption that all banked DG production always has the same value to the system as the kWh component of the utility’s two-part residential rate.
Separate the utility’s sales function from its obligation to purchase DG production.
- If the utility is required to purchase or bank DG production, do not assume the value of the DG production is equal to the utility rate block avoided by the DG, as net metering does.
- Replace net metering by separately determining the value of the DG production on a time-differentiated basis.

Replace the century-old, two-part residential rate design for utility retail sales with a three-part rate design, at least for DG (and, until eliminated, NEM) customers:
- Fixed distribution and customer-related costs ($21 to $32/single-phase residential customer/month) should all be included in the customer charge component of rates and not in the variable or energy charge component. It may be necessary to address the needs of low income customers through assistance programs or other mechanisms, but the number of low-income customers with DG will likely be limited.
– Demand-related costs of distribution, transmission and generation ($25 to $68/single-phase residential customer/month) and any fixed costs not included in the customer charge should be included in the demand component of rates. 
– The energy component of rates should include only variable costs and should be charged on a time differentiated basis. 
– The combination of demand charges and time-differentiated energy component provides a desirable disincentive for the DG customer to use system service in a manner that creates needle peaks while at the same time providing a desirable incentive to maximize DG production at the time that it has the highest value to the utility system.
Since DG customers (with and without net metering) will have a different cost of service than the average residential customer, it would not be unreasonably discriminatory to apply three-part rates only to DG customers. Unless there were other reasons to install an AMI system for all customer groups, the necessary metering for applying three-part rates to DG customers could be accomplished by demand metering with time-of-use or interval recorders (approximately $210/installation plus incremental customer service & administration costs of $1.50 to $2/ single-phase residential DG customer/month).

Until two-part residential rates are replaced, decrease the amount of distribution & customer service fixed costs in the variable component of rates & instead include those costs in the customer charge component.

Unbundling of costs is essential to the above rate design changes; the rate design changes may be easier to explain & understand if rates are also unbundled.