Opening Remarks of Travis Kavulla

Vice President, Regulatory Affairs, NRG Energy

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I generally conceptualize demand flexibility opportunities into three types of business models.

First there is what I would call the "organic" behavior of the demand side in the electricity market: demand acting as demand in relation to the price of electricity and its various component goods, including energy, capacity, transmission, and distribution. This can be consumers reacting themselves, or through a retailer or similar provider that acts as their agent to avoid the costs (and make investments to avoid such costs) that result from those emergent price signals. Retail pricing tends to be flat for residential consumers, but a variety of states have introduced time-varying rate designs as an opt-out such that customers now face this price signal by default. Meanwhile, when a competitive retailer serves customer load, its cost of goods sold are time-variable and can be highly dynamic. Consider the swings in energy price in ERCOT. Or in PJM, where transmission service is generally part of competitive supply, the coincident peak usage of a customer drives the cost their retailer will incur. The retailer can then establish creative retail offerings using pricing, or it can offer other inducements, like a rebate or free gear, in exchange for directly managing certain loads to avoid those upstream costs. This is how NRG's 1 GW VPP in Texas is being constructed. With the rise of automation and controllable distributed energy resources, this organic paradigm—demand acting as demand in response to prices—is more plausible than it ever has been.

The second business model is what has come to be known as capital-D, capital-R "Demand Response": the dispatchable attributes of a flexible load that is jerry-rigged as a *supply* resource into the wholesale markets. This market was invented out of whole cloth by the Federal Energy Regulatory Commission, and it summoned into being the firms today responsible for the largest volumes of demand-flexibility in the United States today. It exists exclusively in the FERC-regulated Regional Transmission Organizations, in addition to a small market for certain ancillary services in ERCOT.

And third and finally you have regulated utility programs that procure demand flexibility in the same way that these monopolies procure everything else: sometimes through an RFP or through a competitive solicitation, sometimes through an avoided-cost-based tariff, and sometimes because you know Bob and Bob seems like a good guy. This also is an act of jerry-rigging demand response into less of an organic act of consumer-side behavior, but unlike DR, the marketplace here is monopsonized—with the utility as sole buyer—and (here I am forced to say a nice thing about utilities) also can be created around certain elements of utility service, like the deferral of distribution circuit upgrades, that are very difficult to price in the more liberalized approaches of the first two. Also, utilities don't like competition, and this "if you can't beat them, buy them" approach reflects a happy co-optation for the utility to get a bunch of miscreant DERs on their side of the regulatory line, while providing revenue to DERs that might not have the ambition to do things 1 or 2.

You can probably tell where my sympathies lie in this debate! However, the conditions necessary to obtain the platonic ideal of Option 1 do not often—perhaps never—obtain. Even in Texas, residential retail electric providers do not face price exposure to the time-varying characteristics of all the constituent elements of electricity service; for residential customers there, transmission is priced flat and so there is no "value stack" on anything besides the costs of energy and ancillary services. In the eastern restructured markets, retailers do face more of the "value stack"—in New Jersey's PSEG service territory last year, nearly half of our cost of goods sold as a retailer was transmission—but the balkanization of utility service territories and the lack of standardization (which does exist in places like Texas thanks to Smart Meter Texas and ERCOT's responsibilities in the retail market) imposes significant transaction costs and can prevent scaling up a flexible-demand-oriented retailer. To give a very concrete example, if you are our customer right here, you have a smart meter on your house—but the local utility is not actually using that smart meter to measure your peak demand for the purpose of establishing your capacity and transmission obligations. Instead, your obligation to purchase capacity and transmission is based on a hypothetical load profile. However, if you lived an hour's drive up the 476 in Allentown, your utility there would use your meter to settle for capacity and transmission—allowing us, your retailer, to create a business model around demand flexibility.

So let me end by observing that given the fact that we have a 50 different regulatory models—or really hundreds, one for each utility it often seems—some combination of these three options is inevitably going to be the future of demand flexibility. And though I'd love to be a purist, the more offensive thing than poorly designed avenues to incorporating demand flexibility into the power sector is not doing so at all.