Title 4—DEPARTMENT OF
ECONOMIC DEVELOPMENT
Division 240—Public Service Commission
Chapter 22—Electric Utility Resource Planning

4 CSR 240-22.055 Distributed Energy Resource Analysis

PURPOSE: This rule specifies the minimum standards for the scope and level of detail required for distributed energy resource analysis and reporting. Distributed Energy Resources are to be evaluated as part of the resource planning process, but due to the rapidly evolving technology, relative speed of deployment, and site specific characteristics, this regulation requires some targeted analysis that is different from other portions of chapter 22.

(1) Definitions. For purposes of this rule:

(A) Customer-generator means a customer owned qualified electric energy generation unit that meets the criteria set forth in 4 CSR 240-20.065(1)(C);

(B) Congestion means a situation where the desired amount of electricity is unable to flow due to physical limitations;

(C) Distributed Energy Resources (DER) means resources sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. Examples of different types of DER include solar photovoltaic, wind, combined heat and power (CHP), energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE);[1] and

(D) Planning horizon means a future time period of at least three (3) years' duration over which the costs and benefits of alternative resource plans are evaluated.

(2) Existing DER database. Utilities shall be responsible for maintaining the following information:

(A) Existing DERs presently connected to the utility's grid;

(B) Information characterizing the distribution circuits where DERs are connected;

(C) Aggregate capacity of DERs for each feeder or load; and

(D) Relevant interconnection standard requirements that specify DER performance of legacy and modern DER.

(3) Market potential for DER. As part of each triennial compliance filing, the utility will consider, at a minimum, the market potential for cost-effective DER within its service territory to help fulfill the fundamental planning objective set out in 4 CSR 240-22.010. This study must cover no less than a three year planning horizon, and will consider both utility-owned DER and non-utility-owned DER.

(4) Evaluating DERs as part of the resource planning process. The evaluation must be conducted utilizing the methods described elsewhere in Chapter 22, and as part of the overall resource

[1] NARUC DER Manual at p. 45.

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planning process. The utility will include planning for future levels of DERs, and how they will be integrated into the utility's distribution system.

(A) DER will be considered in the transmission and distribution analysis required by 4 CSR 240-22.045. This includes existing and potential utility-owned DER and non-utility-owned DER. The utility will describe and document:

1. Areas of congestion which could be improved by DERs;
2. Avoided transmission and distribution (T&D) costs as defined in 4 CSR 240-22.045(2) associated with decreased congestion; and
3. Acceleration or modification of planned T&D improvements and associated costs.

(B) Evaluation of future deployment of cost-effective DER is to be based on utility-owned or managed DERs.

(C) DERs will be examined as part of the demand side resource analysis in accordance with 4 CSR 240-22.050.

(D) The utility will evaluate the potential for integration of DERs to impact grid reliability, to reduce peak demand, and to delay or reduce the size of supply-side resources additions.

(E) In addition to other requirements, DERs will also be modeled, considered, described and documented by the utility consistent with RTO requirements to do so.

(F) The evaluation must cover no less than a three year planning horizon, on a year by year basis to assess annual and cumulative impacts of DER deployment. The utility is not required to utilize a twenty (20) year planning horizon as required elsewhere in Chapter 22.

(G) When assessing opportunities to reduce transmission network losses among the supply-side resources pursuant to 4 CSR 240-22.045(1)(A), the utility must conduct a detailed line-by-line analysis of the transmission and distribution systems. This assessment will be conducted on existing and potential utility-owned DER, as well as existing non-utility-owned DER.