Integrated Planning Including Demand Response, Transmission, and Distribution

A Piece to Elicit Discussion

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This is one of three papers that will be used to stimulate discussion among stakeholders at a May 2, 2007 meeting at the Northwest Power and Conservation Council offices in Portland. The meeting and follow on work will be aimed at supporting an October 2007 report to the utility regulators in the Northwest states of Washington, Oregon, Idaho, and Montana. This paper focuses on how we might integrate transmission and distribution planning into a utility's Integrated Resource Plan (IRP). The two other papers address how we should measure the cost-effectiveness of Demand response (DR), and the design of retail pricing strategies to foster Demand response.

Each of the papers will have a similar approach. We begin by asking what could be done with no limitation to the data and models required to answer the questions posed in each paper. This gives us a sense of what we might want to do in the way of data development and tools development over the long term. We then raise the question of data and tool limitations to help us determine whether we can develop useable techniques, given the limitations.

Each of the papers will be open-ended, because they are designed to elicit brainstorming among participants at the May 2nd meeting. At that meeting and beyond we will examine the available data and tools and what can be done with them in the short term. We can also discuss what should be done to improve our abilities to plan in the future.

Introduction: Integrated Resource Planning (IRP) has traditionally been used within utilities to address the relative cost-effectiveness of central station generating alternatives versus conservation of energy and demand response at the end use. These plans generally (not rigidly) guide investments. In this paper we will explore how to broaden IRPs to include transmission planning and distribution planning.

Background

Integrated Resource Planning (IRP) has traditionally been used within utilities to address the relative cost-effectiveness of central station generating alternatives versus conservation of energy and demand response[1] at customers' facilities. These plans generally guide investments. Other departments within utilities have carried out planning for transmission and distribution in each utility, and rarely have T&D planners coordinated with those utility staff doing IRP. In fact, in many ways T&D planners are competing against resources addressed by IRPs, but without a clear sense of which resources are more valuable. Projects compete to be included in the utility capital plan. Without knowing the relative value of each resource, mistakes can be made.

[1] Demand response has not been universally applied, but some farsighted utilities are now seeing DR as a useful resource in its mix of all resources.

In large utilities, transmission planning may be done by a different group of people than the distribution planning. In smaller utilities, they may be the same. In either case, transmission planning often involves negotiating or reviewing the role of new transmission in a larger regional context through processes at WECC. Distribution does not have this dynamic, usually. In any case, this balkanization of planning has led to inefficiencies in planning and operation of the entire grid.

The grid—from generation through and including loads—has been referred to as a giant machine. Unfortunately we have designed and operated this machine unlike any other. We have not treated the grid as the giant machine that it is. If we designed and operated automobiles, e.g., the way we design and operate the grid, they would not be very reliable. Imagine if separate entities designed the component parts of an automobile without coordinating. The engine, transmission, steering, suspension, and other component parts would not be tuned to one another. Who would buy such a vehicle? But, that is exactly what we have done with the grid.

This effort of the PNDRP is aimed at fixing the disconnect that is the historical norm for planning and operating the grid. At the May 2, 2007 meeting we will examine the benefits of a comprehensive IRP that includes all aspects of the grid, not only generation and demand options. Between the May 2 meeting and the fall of 2007, we will continue to work on the issues based on discussions of May 2 to draft a report to Northwest regulators for their consideration. In short, transmission and distribution planners need to have the full panoply of distributed resources as tools in their toolbox. If they lack awareness of DR potentials as solutions to their planning objectives, then these solutions will not be deployed.

Discussion: Coincident peak loads, those that, in part, drive the need for additions to transmission, infrequently occur — perhaps a hundred hours per year. The same can be said for peak loads on distribution feeder lines, which may or may not correspond to system coincident peak loads.

Yet, standard practice is to build transmission and distribution facilities for these loads without carefully examining other potentially far less costly alternatives. Transmission cost for loads that occur only one hundred hours per year are very high depending on whether utilities maintain transmission throughout the year to meet peak loads. Both the costs per kWe and per kWh of transmission to serve peak loads can be very high. Loads at this level may return less revenue than the costs to serve, and should be a ripe target for utilities DR programs. In addition, these loads may serve to drive up wholesale prices to very high levels – prices that are, in turn, paid by all customers

An IRP that includes T&D would be able to compare the price of both transmission and distribution at the margin with other options, including time of use pricing, demand response programs, etc. and to determine if there are less costly options than simple building transmission and distribution without regard for alternatives.

The Bonneville Power Administration has been conducting a review of non-wire opportunities for the last several years and has developed pilot projects for the Olympic Peninsula and Coos-Curry area of southwest Oregon. Neither of these pilots has been implemented as yet, and only Coos-Curry is still being contemplated. The Olympic Peninsula project was shown to be cost-effective until the standards were changed to require N-2 planning criteria for the Olympic Peninsula transmission lines.

How do we integrate T&D into integrated resource plans?

Ideally, we would like to have a comprehensive model of the entire grid that could estimate the relative trade offs between and among all of the various options within the "big machine" that is the grid. However, this model, if it can be done, seems to be in the future. What do we do now, with existing relationships among utilities, planners, regulators, etc., and with our existing tools and knowledge level?

We can all probably agree that the first step within a single utility is coordinating transmission and distribution planners with those staff engaged in IRPs. Behind this simple statement lies a lot of work. The following questions, at a minimum, need to be answered. When transmission planning is done at a regional or wider level, additional coordination will be needed. See 4., below.

Discussion:

1. What is current relationship between schedules for T&D planning and IRP preparation?

2. How can we schedule the planning sequences of T&D planners with IRPs so that they mesh?
    a. Buy-in from utility officials.

    b. Buy-in from regulators? Will the different goals of state regulators be a major hurdle when dealing with an integrated grid and several utility operators?

    c. Buy-in from T&D Planners?

    d. Other?

3. Do we need new tools or just new processes? Would a rational top-to-bottom planning function using existing tools and data suffice? Is it the first step?

4. Does west coast or regional transmission planning become a rigid constraint to IRP planning, or can we arrange a way to iterate with entities doing planning outside of the utilities' sphere, but having clear affect on the utilities?

5. How do we compare the carrying capacity of new transmission versus what DR resources are available. If transmission is being planned to avoid a specific pinch point in the grid, what is the effect of DR on lines remote from that point, e.g.? Flow factors will be needed.

6. Is transmission designed to meet renewable obligations, e.g., to be looked upon as a constraint? Are there other ways to look at these lines?

7. Transmission by definition is built prior to need. We will probably have to change our concept of DR to build or arrange for it before need also. Can we work to assure a reasonable level of connection and comparison between heretofore disconnected resource planning and investment? A goal should be transparency, sufficient planning horizon (10 yr min), and an opportunity for all planners to see system concerns with sufficient time to assemble the best investment plan from all options. How, or does, FERC Order 890 affect this discussion?

8. Today utilities do an Environmental Impact Statement that purportedly looks at all options. But, without the kind of look we are suggesting here it would be difficult to look at DR and come up with a good comparison of its costs relative to the costs of the transmission line. The approach being discussed here could add to the transparency of transmission planning.