22. Improve Utility Resource Planning Practices[1]

1. Profile

This chapter examines the potential for utility resource planning processes to support the efforts of states to reduce greenhouse gas (GHG) emissions from the electric power sector. It will focus on a particular type of planning process called integrated resource planning. This process, as well as any plan produced by the process, is commonly referred to by the acronym "IRP."

An IRP is a long-range utility plan for meeting the forecasted demand for energy within a defined geographic area through a combination of supply-side resources (i.e., those controlled by the utility) and demand-side resources (i.e., those controlled by utility customers). Generally speaking, the goal of an IRP is to identify the mix of resources that will minimize future energy system costs while ensuring safe and reliable operation of the system.[2] Most IRPs look 10 to 20 years into the future, and are updated every two to three years.

An IRP may be developed by a utility or power marketing administration for its service territory in one or more states, or by a utility commission for its entire state. In some states, utility plans serve as a blueprint for resource acquisition decisions and are subject to approval by the public utility commission (PUC). Plans covering a multistate area are more likely to be used for educational purposes only.

In the process of developing an IRP, planners may consider a wide range of alternatives to meet future energy needs. The alternatives can include reducing demand through energy efficiency programs or rate design, adding generation capacity, encouraging customer-owned generation and combined heat and power facilities, adding transmission and distribution lines, reducing line losses in the transmission and distribution system, and implementing demand response programs.[3] Planners can also consider relevant state and federal policy requirements, such as state renewable portfolio standards, state energy efficiency resource standards, and federal acid rain program requirements.

1 Portions of this chapter are adapted from three publications for which The Regulatory Assistance Project was lead author or client: (1) State and Local Energy Efficiency Action Network. (2011, September). *Using Integrated Resource Planning to Encourage Investment in Cost-Effective Energy Efficiency Measures.* Available at: https://www4.eere.energy.gov/seeaction/publication/using-integrated-resource-planning-encourage-investment-cost-effective-energy-efficiency; (2) Wilson, R., & Biewald, B. (2013, June). *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans.* Synapse Energy Economics for The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6608; (3) Farnsworth, D. (2013, March). *Addressing the Effects of Environmental Regulations: Market Factors, Integrated Analyses and Administrative Processes.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6455

2 Nearly all utilities and utility regulators across the country have practiced some form of least-cost resource planning for decades. But in the past, many of these least-cost resource plans exclusively considered procurement of supply-side resources. The availability of energy efficiency and other demand-side resources at very low costs and in significant quantities was often ignored in the planning process. An IRP can be very similar to a traditional least-cost resource plan, with the distinction that a process or plan that doesn't consider demand-side resources is not an IRP. Although "traditional" least-cost planning continues in some locations and may be relevant to this chapter, IRP is much more widely practiced and more suitable for use in the context of GHG emissions reductions.

3 Not every IRP considers every alternative listed. The alternatives considered will vary based on state and local regulatory requirements and based on what type of entity is developing the plan. In particular, the planning for transmission lines in areas served by a regional transmission organization is commonly done through a separate process as described in Chapter 18.

The basic steps in an IRP process have been summarized by one expert as follows:[4]

1. Forecast load, fuel and market power prices, and other key factors, such as likely environmental regulations or market changes;
2. Document costs and benefits of existing supply-side and demand-side resources, including existing generation and transmission facilities, purchase contracts, energy efficiency and demand response programs, and market purchases of power; study their strengths and weakness, challenges and opportunities;
3. Identify and characterize new supply-side and demand-side resources that could be acquired over the life of the IRP;
4. Develop different resource plans that could meet future load requirements, and screen them based on cost;
5. Select the best resource plans and test their sensitivity to risk factors such as load uncertainty, fuel price volatility, and regulatory uncertainty;
6. Select a preferred plan, usually based on a combination of lowest present value life-cycle cost (under one or another definition of cost) and risk profile; and
7. Develop an action plan for the near term, often three to five years, depending on the construction lead-time of the selected resources.

Figure 22-1

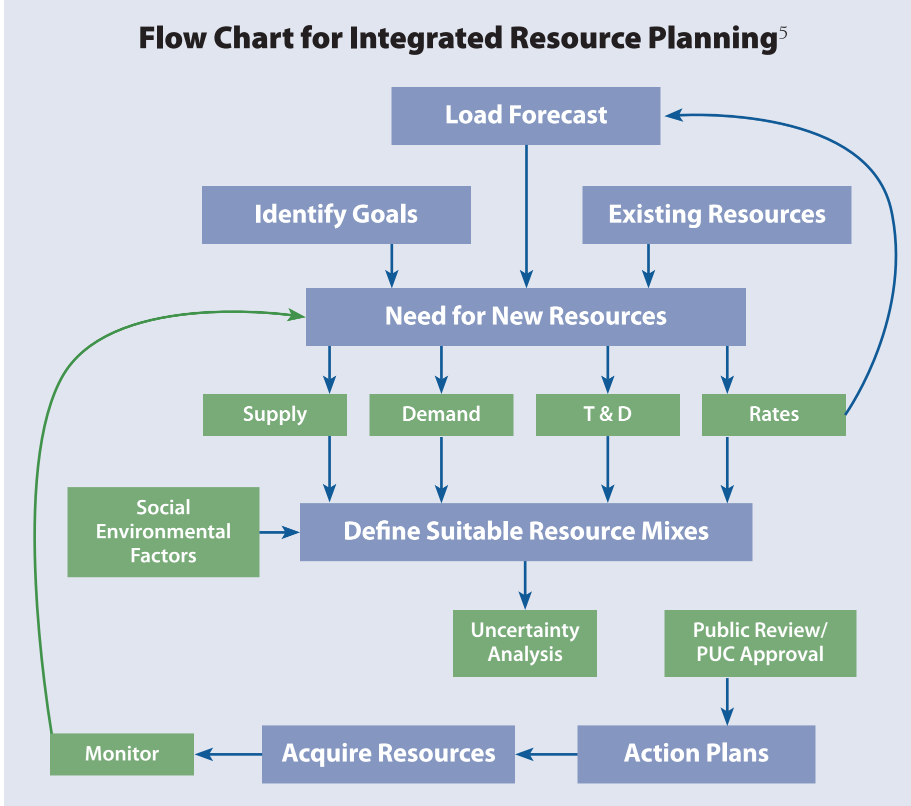


Figure 22-1 depicts a similar interpretation of the steps in an IRP process by a different expert.

In a 2013 publication, The Regulatory Assistance Project and Synapse Energy Economics provided recommendations for the substantive aspects of IRPs that are designed to result in responsible and comprehensive plans:[6]

1. **Load Forecast.** A company's load forecast (annual peak and energy) is one of the major determinants of the quantity and type of resources that must be added in a utility's service territory over a given time period, and has always been the starting point for resource planning.

4 Biewald, B. (2011, October 17). *Review of Resource Planning Around North America*. Synapse Energy Economics, Inc. Available at: http://synapse-energy.com/project/review-resource-planning-around-north-america The seven specific process steps referenced also appear in: Resource Insight, Inc. and Synapse Energy Economics, Inc. for the Ohio Consumers Council. (2006, June). *Integrated Portfolio Management in a Restructured Supply Market*, pp. 37–38. Available at: http://www.occ.ohio.gov/reports/ipm/pdfs/irp_report.pdf

5 Adapted from: Hirst, E. (1992, December). *A Good Integrated Resource Plan: Guidelines for Electric Utilities and Regulators*. Oak Ridge National Laboratory. The figure as shown here appears in: Harrington, C., Moskovitz, D., Austin, T., Weinberg, C., & Holt, E. (1994, June). *Integrated Resource Planning for State Utility Regulators*. Montpelier, VT: The Regulatory Assistance Project. Available at: http://raponline.org/document/download/id/817

6 Wilson, R., & Biewald, B. (2013, June). *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans*. Synapse Energy Economics for The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6608

Projections of future load should be based on realistic assumptions about local population changes and local economic factors and should be fully documented.

2. **Reserves and Reliability.** Reserve requirements should provide for adequate capacity based on a rigorous analysis of system characteristics and proper treatment of intermittent resources. The system characteristics affecting reliability and reserve requirements include load shape, generating unit forced-outage rates, generating unit maintenance-outage requirements, number and size of the generating units in a region or service territory, transmission interties with neighboring utilities, and availability and effectiveness of intervention procedures.
3. **Demand-Side Management.** The best IRPs create levelized cost curves for demand-side resources that are comparable to the levelized cost curves for supply-side resources. By developing cost curves for demand-side options, planners allow the model to choose an optimum level of investment. So if demand-side resources can meet customer demand for less cost than supply-side resources, as is frequently the case, this approach may result in more than the minimum investment levels required under other policies.
4. **Supply Options.** A full range of supply alternatives should be considered in utility IRPs, with reasonable assumptions about the costs, performance, and availability of each resource.
5. **Fuel Prices.** Fuel prices can shift as a result of demand growth, climate legislation, development of export infrastructure, and supply conditions. It is thus extremely important to use reasonable, recent, and consistent projections of fuel prices in IRP.
6. **Environmental Costs and Constraints.** Utility IRPs should include a projection of environmental compliance costs – including recognition, and evaluation where possible – of all reasonably expected future regulations.
7. **Existing Resources.** Examination of existing resources in utility IRPs has become especially important as the mandated emissions reductions associated with the Mercury and Air Toxics Standards have led to utility decisions across the country to install pollution control retrofits, repower, or retire their coal units.
8. **Integrated Analysis.** There are various reasonable ways to model plans, generally requiring the use of optimization or simulation models. Common models used throughout the industry include Strategist, Electric Generation Expansion Analysis System, System Optimizer, MIDAS, AURORA, PROMOD, and Market Analytics.
9. **Sufficient Time Frame.** The study period for IRP analysis should be sufficiently long to incorporate much of the operating lives of any new resource options that may be added to a utility's portfolio – typically at least 20 years – and should consider an "end effects" period to avoid a bias against adding generating units late in the planning period.
10. **Uncertainty.** At a minimum, important and uncertain input assumptions should be tested with high and low cases to assess the sensitivity of results to changes in input values. These assumptions include, but are not limited to, load forecasts, fuel prices, emissions allowance prices, environmental regulatory regimes, costs and availability of demand-side management measures, and capital and operating costs for new generating units.
11. **Valuing and Selecting Plans.** There are often multiple stages of running scenarios and screening in developing an IRP, and there are various reasonable ways to approach this. Traditionally, the present value of revenue requirements is the primary metric that is analyzed, and minimized, in utility IRPs. This metric alone may not, however, sufficiently address uncertainties. It may be useful also to evaluate plans along other dimensions such as environmental cost or impact, fuel diversity, impact on reliability, rate or bill increases, or minimization of risk.
12. **Action Plan.** A good plan will include a specific discussion of the implications of the analysis for near-term decisions and actions, and will also include specific plans for getting those near-term items accomplished.
13. **Documentation.** A proper IRP will include discussion of the inputs and results, and appendices with full technical details. Only items that are truly sensitive business information should be treated as confidential, because such treatment can hinder important stakeholder input processes.

A utility resource plan does not compel emissions reductions, but the utility's decisions on how to treat each of the elements listed previously will greatly influence the perceived feasibility of unit retirements, the relative benefits of demand-side resources, the need to deploy new supply-side resources, the selection of the preferred resources, and – importantly for the purposes of this document

– the resulting air quality impacts. Done poorly, an IRP could result in increased emissions of GHGs and other air pollutants. However, an IRP based on the previous 13 recommendations will give due consideration to emissions and air pollution regulatory requirements and will reveal the impacts of different potential resource portfolios in a way that can aid utility planners and air quality planners. Best of all, it creates a means for utility planners to incorporate environmental considerations in routine processes that are core (not peripheral) to their mission.

As indicated in Figure 22-1, a good IRP process will include at least two steps that create the possibility of *directly* addressing emissions. First, regulatory requirements and public policy preferences – including those for GHG emissions – can be identified as conditions that must be met by any selected resource plan. For example, a goal could be established for the overall GHG emissions or emissions rate that must be achieved through the IRP, and any resource portfolios that fail to meet that goal will be rejected. Second, regardless of whether explicit emissions goals are identified, social and environmental factors (including GHG emissions) can be introduced into the analysis to influence the final selection of the preferred resource mix. For example, without establishing a hard limit on GHG emissions, an assumed regulatory cost or social cost could be assigned to each ton of GHG emissions, which would increase the relative cost of resource portfolios that have relatively high emissions and make those portfolios less likely to be selected for the plan.

2. Regulatory Backdrop

Integrated resource planning rules were first established in many states in the late 1980s or early 1990s. At that time, the electric power sector was dominated by vertically integrated monopoly utilities that owned and had responsibility for generation, transmission, and distribution assets. Many state policymakers saw the value of requiring these utilities to adopt formal, comprehensive IRP processes to ensure reliable and affordable service.

Significant changes to the electric power industry occurred in the ensuing decades. During the mid to late 1990s, electric restructuring occurred in parts of the country, with competitive service providers taking over some of the roles that had been filled by vertically integrated utilities. The wholesale generation side of the industry became competitive in many states, and retail competition was introduced in a smaller but still significant number of states. Although all of these changes affected the scope of the utility's role and in some cases relieved the utility from its responsibility for certain aspects of long-term planning, a majority of states continued to see value in some form of planning process and retained mandatory requirements with changes to the original rules as necessary. For example, in states that have introduced retail competition, utilities may be required to develop long-term plans for their distribution system along with a plan for providing comprehensive service to customers who don't choose a competitive energy supplier.

State IRP rules in their current forms have been established in a number of ways. In certain states, legislatures passed bills into law mandating that utilities engage in resource planning; in others, IRP rules were codified under state administrative code. Some state PUCs adopted IRP regulations as part of their administrative rules, or ordered it through docketed proceedings. Rules have also been developed through a combination of these processes.[7,8]

Figure 22-2 shows the states that have instituted requirements for IRPs, or similar documents, to be prepared by some or all electric utilities. Each state has its own requirements for the scope, timing, and contents of an IRP, and its own requirements as to how that state's PUC analyzes and reviews the IRP once it is submitted.[9] Section 3 provides best practice IRP examples and regulatory or statutory citations for several states and two regional transmission organizations (RTOs).

There is also one notable example of a federal resource planning requirement. *The Pacific Northwest Electric Power Planning and Conservation Act of 1980* requires the Northwest Power and Conservation Council, a regional planning organization, to develop IRPs for the Bonneville Power Administration (BPA). BPA transmits and sells wholesale electricity from federal hydroelectric and nuclear generating stations to utilities in eight western states. These

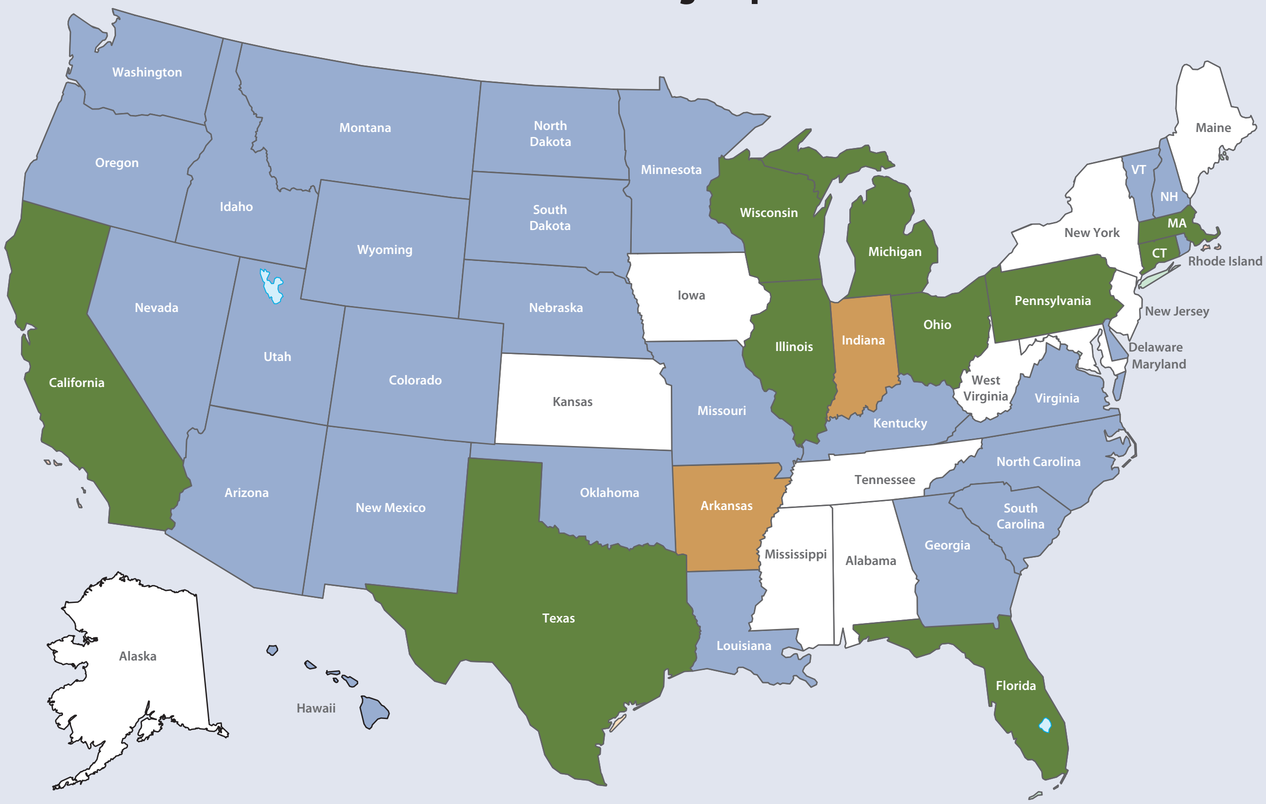
7 Supra footnote 6, at p. 6.

8 In addition, some states have adopted special studies or special planning requirements outside of routine IRP requirements to address air pollution issues or other issues of particular concern to policymakers. Although this chapter focuses primarily on IRP, some of these special planning exercises are particularly relevant to GHG emissions reduction planning and are noted throughout the chapter where appropriate.

9 Many of these details are summarized in Supra footnote 6.

Figure 22-2

State Resource Planning Requirements[10]



State has an IRP rule and filing requirement

State is developing or revising an IRP rule and filing requirement

State has a filing requirement for long-term plans

State does not have filing requirements for long-term plans

plans have a profound effect on the operations of BPA and its client utilities, especially in Washington, Oregon, Idaho, and Montana.

Today, climate change, national security concerns, distributed generation, and volatility in fuel and commodity markets are adding to the challenges of forecasting and planning for the future. These challenges do not detract from the value of IRP, but rather make it more valuable even as it becomes more difficult. This underscores the point that IRP rules need to be reexamined periodically to make sure they reflect the current conditions and challenges associated with providing reliable electric service at reasonable costs.[11]

One important area in which state IRP requirements differ significantly is the extent to which stakeholders can engage in the process. Typically the process begins when the PUC opens a docket and requires a utility to prepare (or update) an IRP. In some states, the utility will be required to engage stakeholders at the beginning of the planning process, but other states only engage stakeholders after the IRP is drafted. Stakeholders (including air pollution experts) can add value to the IRP early in the process by raising issues and providing data that might otherwise be excluded from consideration. After the utility has completed its analysis, it typically submits the IRP in draft or final form to the PUC. At that point, the PUC may open a comment period, or schedule (or require the utility to schedule) hearings, technical conferences, or workshops to inform stakeholders about the IRP and give them an opportunity to comment. However, states will vary in how many of the data in the analysis are treated as confidential, and this can limit the meaningful participation of stakeholders. The final step in the review process also varies considerably from state to state. Some PUCs will

10 Supra footnote 6.

11 Ibid.

merely review and "acknowledge" the IRP, whereas others will judge the merits of the plan and may order the utility to make changes to the plan or conduct additional analysis.

Expanding on this last point, air pollution regulators need to understand that IRPs are not intended to be enforceable documents that can be used against a utility that deviates from the plan, nor are they intended to give the utility unconditional approval to implement whatever is in the plan. Approval of an IRP by a PUC generally does not relieve the utility from the need to ultimately demonstrate to the PUC that its investments are optimal and consistent with the plan, given *actual* (as opposed to *forecast*) conditions. PUC approval may, however, convey a rebuttable presumption that the projects described in the plan are necessary and prudent. In Oregon, for example: "Consistency with the plan may be evidence in support of favorable rate-making treatment of the action, although it is not a guarantee of favorable treatment. Similarly, inconsistency with the plan will not necessarily lead to unfavorable rate-making treatment, although the utility will need to explain and justify why it took an action inconsistent with the plan."[12] Similarly, in Idaho the PUC stated that it would "continue to hold that the plans are not to be given the force and effect of law, [but] we presume that utilities intend to follow the plans after they have been filed for our acceptance. Deviations from the integrated resource plans must be explained. The appropriate place to determine the prudence of an electric utility's plan or the prudence of an electric utility's following or failing to follow a plan will be in a general rate case or other proceeding in which the issue is noticed."[13]

3. State and Local Implementation Experiences

IRPs are routinely developed and updated on a regular basis by hundreds of utilities across the country. Rather than summarizing all of those experiences, this section offers an example from Arizona of established good practices for IRP that have been used to explore interconnected environmental, energy, and ratepayer issues.[14] In addition, this section features examples of some utility resource planning exercises that were instituted to specifically address air quality issues and supplement normal IRP processes. These special planning exercises not only demonstrate what is possible through separate, air quality-related planning efforts, but also suggest ways in which routine IRP processes can be modified to better account for air quality goals and regulations.

Arizona[15]

Arizona Public Service (APS) is the state's largest electric utility, and has been serving retail and wholesale consumers since 1886. In March 2012, APS filed the first formal resource plan in 17 years with the Arizona Corporation Commission. This IRP was also the first to be filed under the Arizona Corporation Commission's revised rules. From the time when the Corporation Commission issued the final IRP rules to the date that APS filed its resource plan, the utility was "engaging key stakeholders to gain an understanding and appreciation of their areas of concern."[16] The plan also serves as a framework to evaluate APS's resource plans as they relate to other policy requirements for renewable-sourced generation and regulator-imposed energy efficiency obligations.

APS had forecast three percent average statewide annual growth in nominal electricity requirements through 2027. Energy efficiency and distributed generation, in the form of rooftop solar installations, will help offset some of this growth, but APS expects that it will need to add additional conventional supply-side resources, in the form of natural gas-fired generation, in 2019. APS has created four resource portfolios to evaluate: a base case, a "four corners contingency," an "enhanced renewable" case, and a "coal retirement" case.

Each resource plan created by APS was analyzed using a production simulation model, which dispatches the energy resources in each portfolio and generates system costs, or likely future revenue requirements, associated with each. Calculation of system revenue requirements demonstrated that the APS base case portfolio was the most cost-effective of the resource plans evaluated. APS also monitors specific metrics to provide a context for comparing and evaluating the portfolios. In addition to revenue requirements, those metrics include fuel diversity, capital expenditures, natural gas burn, water use, and carbon dioxide (CO_2) emissions.

APS selected major cost inputs and evaluated several sensitivity scenarios, setting the assumptions for these variables higher or lower to test the impacts on the specific metrics being evaluated. These major cost inputs include

12 Oregon PUC Order No. 89-507 at 7.

13 Order 25260 from Case #GNR-E-93-3.

14 Other examples can be found at: Supra footnote 6.

15 Adapted from: Ibid.

16 Arizona Public Service. (2012, March). *2012 Integrated Resource Plan,* p 2.

natural gas prices, CO_2 prices, production and investment tax credits for renewable resources, energy efficiency costs, and monetization of sulfur dioxide (SO_2), nitrogen oxides (NO_X), particulate matter, and water. APS also created low-cost and high-cost scenarios, which incorporate the low and high values for all of the variables mentioned previously rather than testing them on an individual basis. The results of the sensitivity analysis showed that the four corners contingency and coal retirement portfolios have the most variability in terms of net present value of revenue requirements, which fluctuate 11 to 12 percent as compared to 6 to 7 percent for the base case and enhanced renewable portfolios. Natural gas price changes caused the largest impact on sensitivity results.

Under the base case plan, APS achieves compliance with energy efficiency requirements and slightly exceeds compliance levels for renewable energy. Consistent with the intent of the revised rules, APS's reliance on coal-fired generating resources drops by 12 percent between 2012 and 2027. Use of natural gas increases slightly over the course of the planning period under this scenario, but by 2027, no single fuel source makes up more than approximately 26 percent of the APS resource mix.

APS had approximately 600 megawatts (MW) of excess capacity in 2012, heading into the summer peak. In the short term – over the next three years – the company planned to continue to pursue energy efficiency and renewable energy resources. During the intermediate term, years 4 to 15 of the planning period, APS plans to add 3700 MW of natural gas capacity and 749 MW of renewable capacity. However, "[i]n the event that solar, wind, geothermal, or other renewable resources change in value and become a more viable and cost-effective option than natural gas, future resource plans may reflect a balance more commensurate to the Enhanced Renewable Portfolio."[17]

Several features of the IRP efforts of APS are worth highlighting. The first of those is the comprehensive stakeholder process. Not only were stakeholders invited to listen and offer feedback, they were also invited to present their points of view on a subset of these important issues. In the IRP itself, APS provides all non-confidential input and output data for stakeholder review.

APS continues to pursue energy efficiency, renewable energy, and distributed generation resources in each of the resource portfolios it analyzed, meeting or exceeding regulator-identified goals.

APS has also analyzed portfolios that meet the Commission goals of promoting fuel and technology diversity as the utility lowers its reliance on coal-fired generation and increases its use of energy efficiency and renewable energy resources.

In addition, APS takes environmental costs into account when evaluating its resource plans. The company uses a CO_2 adder consistent with the assumption that federal regulation of CO_2 will occur within the 15-year planning period.[18] In sensitivity scenarios, APS analyzes alternative prices for CO_2 emissions, and also includes adders for SO_2, NO_X, particulate matter, and water. Emissions costs and water consumption are also two metrics by which APS evaluates its resource portfolios.

Colorado[19]

Colorado, the seventh-largest coal-producing state in the United States, passed the "Clean Air – Clean Jobs Act" ("the Act") in April 2010, targeting regional haze and ozone, and establishing a 70- to 80-percent reduction target for NO_X emissions from 2008 levels. Denver and Colorado's "Front Range" had been designated under the Clean Air Act as "non-attainment" areas for ground-level ozone.

In the absence of final federal regulations, the Act anticipated new EPA standards for criteria air pollutants (NO_X, SO_2, and particulates), mercury, and CO_2, and

17 Supra footnote 16.

18 APS completed this IRP before the US Environmental Protection Agency (EPA) proposed emissions rate limitations for existing electric generating units under section 111(d) of the Clean Air Act. Not knowing what the EPA would propose, APS made reasonable assumptions about the cost impacts of future regulation and tested different scenarios.

19 Farnsworth, at supra footnote 1.

20 The "Clean Air – Clean Jobs Act," HB 10-1365, requires " [b]oth of the state's two rate-regulated utilities, Public Service Company of Colorado (PSCo), and Black Hills/Colorado Electric Utility Company LP … to submit an air emissions reduction plan by August 15, 2010, that cover[s] the lesser of 900 megawatts or 50% of the utility's coal-fired electric generating units." Legal Memorandum, Office of Legislative Legal Services on H.B. 10-1365 and Regional Haze State Implementation Plan. (2011, March 16). Available at: http://www.leg.state.co.us/clics/clics2011a/cslFrontPages.nsf/FileAttachVw/SIP/$File/SIPMeetingMaterials.pdf

required the utility company[20] to: (1) consult with the Colorado Department of Public Health and Environment (DPHE, the state air pollution regulatory agency) on its plan to meet current and "reasonably foreseeable EPA clean air rules," and (2) submit a coordinated multipollutant plan to the state PUC.[21]

The Act mandated that DPHE participate in the PUC process, and conditioned PUC action on the DPHE's review of utility proposals, affirmatively linking the two agencies' actions. This mandate resulted in the PUC being unable to approve a company plan that the DPHE did not agree would meet future Clean Air Act requirements, and the company not being able to build anything without the PUC's approval and issuance of a certificate of public convenience. The Act also required the DPHE Air Quality Control Commission to incorporate approved plans into Colorado's State Implementation Plan (SIP) for addressing regional haze for ultimate EPA approval.

Colorado utilities are not required to adopt any particular plan, just one that meets DPHE's requirements and meets with PUC approval. The Act also encourages utilities to enter into long-term contracts for natural gas supplies by providing protection against possible future prudence challenges by stakeholders. It allows utilities to recover, in rates, costs associated with approved long-term contracts, "notwithstanding any change in the market price during the term of the agreement."

The Act encourages companies to evaluate alternative compliance scenarios, but requires each company to develop and evaluate an "all emissions control" case (i.e., a scenario calling for installation of pollution controls on the coal fleet, plus an assessment of different ranges of retirements).

In the administrative process, the state's largest utility (Public Service of Colorado, doing business as Xcel Energy) was given four months to report to the PUC with analysis results and a proposed compliance plan. The company divided its analysis into four steps (see Table 22-1). In Step 1, the company collected data regarding: (1) the coal plants for which the company might take "action" (i.e., install controls, retire, or retrofit for fuel switching); (2) emissions control options and associated costs; (3) possible generation technologies that would replace retired capacity; and (4) transmission reliability requirements.

Step 2 involved developing combinations of various actions on coal plants, assessing replacement generation (i.e., developing "Capacity Portfolios"), and testing the feasibility of approaches for reducing emissions while maintaining reliable service.

Table 22-1

Public Service of Colorado's Analysis[22]

1. Data Collection
- Identify Candidate Coal Units
- Emissions Control Options and Costs
- Replacement Capacity Options
- Transmission Reliability Requirements

2. Scenario Development
- Meet NO_X Reduction Targets
- Feasibility of Emissions Controls
- Replace Retired Coal MW
- Transmission Needs Analysis

3. Dispatch Modeling of Scenarios
- Long-term Capacity Expansion Plan
- Cost of Transmission Fixes
- Coal and Gas Price Forecasts
- Customer Load Forecasts

4. Sensitivity Analysis
- Construction Costs
- Coal and Gas Prices
- Emissions Costs (NO_X, SO_2, CO_2)
- Replacement MW for retirements
- Addition of renewable resources

In Step 3, the company used its dispatch modeling capability to evaluate the effects of various scenarios (articulated partly by statute, the company, the PUC, and stakeholders) on the company's entire system.

Step 4 involved the development of sensitivity analyses. At this step, the company performed analyses by varying certain key assumptions to see how the scenarios it developed and modeled under Steps 2 and 3 would perform in different futures.

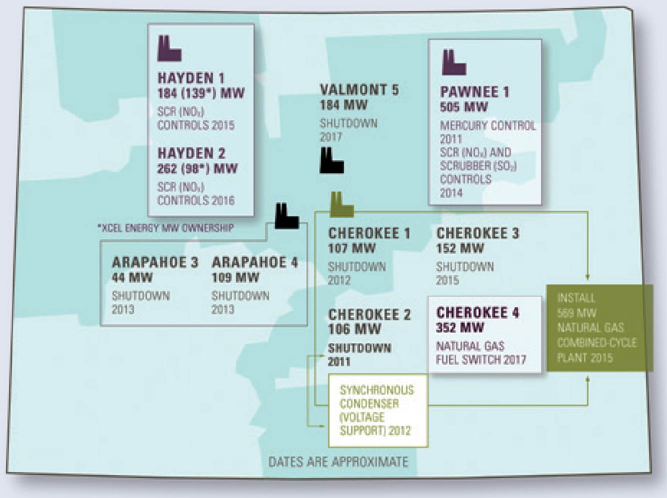
The overall undertaking required cooperation between the regulatory commission and Colorado's environmental regulator, and significant effort by Public Service of Colorado. The process, including a PUC investigation, company analysis of alternative compliance strategies, issuance of a final order, and subsequent adoption of changes to Colorado's SIP, occurred in less than eight

21 Colorado's Clean Air – Clean Jobs Act was specifically identified as a "best practice" by the EPA in its 111(d) proposal.

22 Supra footnote 19.

Figure 22-3

Major Elements of Public Service of Colorado's Approved Plan[23]



months, demonstrating the feasibility of such a cooperative effort and the ability of decision makers to address the challenges related to maintaining system reliability while responding to (as yet unarticulated) health and environmental regulatory compliance challenges. Figure 22-3 provides a visual summary of the major impacts of this planning process.

On March 12, 2012, the EPA approved Colorado's SIP for addressing regional haze around the state's national parks and wilderness areas. Governor John Hickenlooper noted at the time, "EPA's approval of the Regional Haze Plan is a ringing endorsement of a comprehensive and collaborative effort between many different groups… Colorado's utilities, environmental community, oil and gas industry, health advocates and regulators all came together to address air quality. We embrace this success as a model for continuing to balance economic growth with wise public policy that protects community health and our environmental values."[24] Another source quoted in the media at that time said, "The adoption of Colorado's state implementation plan – unlike other states' proposals – went smoothly in large part because of Colorado's 2010 Clean Air – Clean Jobs Act."[25]

The same process steps discussed previously for regional haze and NO_X could also be followed to assess compliance options for the EPA's proposed Clean Power Plan. Step 1 would include data on Colorado's existing renewable energy and energy efficiency programs. Step 2 results would focus on meeting the GHG emissions reduction trajectory from 2020 to 2030 as provided for in the proposed existing source performance standards. The sensitivity analysis in Step 4 could assess the contributions from varying levels of energy efficiency and renewable energy (low, medium, and high), their costs, and effects on Colorado's generating resources. Step 4 could also evaluate the regional effects from energy efficiency and renewable energy, and from improvements to the regional transmission grid (i.e., reduced line losses and improvements to local distribution systems).[26]

It is important to note that the Colorado process:

- Took place in less than one year;
- Went ahead, absent certainty as to precisely what EPA regulations would require; and
- Mandated coordination between environmental and energy regulators, owing to the subject matter of the challenges being addressed by the state.

Michigan[27]

Michigan provides a unique model of regulatory coordination. Executive Directive No. 2009-2 requires the state environmental regulator, the Michigan Department of Environmental Quality (DEQ), to "conduct analysis of electric generation alternatives prior to issuing an air discharge permit." As part of this inquiry, the directive also

23 See: http://www.xcelenergy.com/Environment/Doing_Our_Part/Clean_Air_Projects/Colorado_Clean_Air-Clean_Jobs_Plan

24 Refer to: Colorado.gov. (2012, September 11). Colorado's Air Quality Plan Receives Final Approval from U.S. Environmental Protection Agency. [Press release]. Available at: http://www.colorado.gov/cs/Satellite?c=Page&childpagename=GovHickenlooper%2FCBONLayout&cid=1251630618478&pagename=CBONWrapper

25 Jacobs, J. (2012, March 15). EPA Signs Off on Colorado's Plan for Clearing Haze Near Parks. *Greenwire*. Available at: http://www.rlch.org/news/epa-signs-colorados-plan-clearing-haze-near-parks

26 The EPA's 111(d) proposal did not include transmission and distribution system improvements as part of the four building blocks, but specifically mentions it as a policy that states could evaluate to assess whether such improvements could help reduce GHG emissions.

27 Farnsworth, at supra footnote 1.

requires the Michigan Public Service Commission (PSC) to provide DEQ with technical assistance.[28]

The two agencies entered into a memorandum of understanding in which respective roles were articulated: DEQ would undertake air quality determinations, and the PSC would provide assistance related to determining need for new generation, and analyze alternatives, including options for energy efficiency, renewable energy, and other generation. [29]

The value of this coordinated process was demonstrated when Consumers Energy proposed to construct a new 930-MW coal-fired power plant at the existing Karn-Weadock Generating Station. The utility submitted an Electric Generation Alternatives Analysis to the DEQ and PSC on June 5, 2009. Pursuant to the memorandum of understanding, PSC staff reviewed the Electric Generation Alternatives Analysis and evaluated the long-term capacity need asserted by Consumers Energy as justification for the project. The PSC staff concluded in September 2009 that the project couldn't be justified unless the utility committed to retire certain existing coal-fired units, because of expected low growth rates in electric demand and the potential to meet demand growth less expensively through a combination of energy efficiency, load management (demand response), renewable energy, and purchased power agreements.

Following the PSC staff report, Consumers Energy worked with PSC staff to develop a plan for retiring 958 MW of coal-fired generation capacity as a modification to its original proposal. With those units retired, the need for a new power plant could be demonstrated. DEQ then issued a permit for the new unit on December 29, 2009. But two years later, in December 2011, Consumers Energy canceled the project before construction ever began because of reduced customer demand for electricity and surplus generating capacity in the Midwest market.[30]

Michigan's Executive Directive No. 2009-2, like Colorado's Clean Air – Clean Jobs Act, underscores the value of developing a process that links both environmental and energy regulators to analyze company electric generation choices. In the example provided previously, Michigan avoided the expense and environmental impact of a large coal-fired power plant by coordinating the expertise of the two regulatory agencies and explicitly considering alternatives for meeting project energy demands. A variation on this kind of coordinated process could help Michigan (and other states) develop a feasible and cost-effective state strategy for complying with the EPA's 111(d) rule.

Oklahoma[31]

In June 2011, the Oklahoma Corporation Commission issued a notice of inquiry (NOI) in order to examine existing and pending federal regulations and legislation that could impact regulated utilities and their customers in the state of Oklahoma.[32] The primary purpose of the NOI is to determine whether any amendments to the rules of the Commission are necessary.

In its first of a series of questions, the Commission asked:

> *Are there alternative planning processes other than a regulated utility's Integrated Resource Plan (IRP) as described in OAC 165:35-37 that could be considered in determining the most effective strategy to include a holistic approach to Oklahoma's generation fleet and an analysis of the overall cost impact or benefits to ratepayers as it relates to federal mandates, fuel switching (converting from one fossil fuel to another type of fossil fuel), renewable portfolio standards, fuel diversity, system efficiency improvements, transmission expansions and other upcoming issues? If so, what kind?*

28 Executive Directive No. 2009–2. *Consideration of Feasible and Prudent Alternatives in the Processing of Air Permit Applications from Coal-Fired Power Plants.* Available at: http://www.michigan.gov/granholm/0,1607,7-168-36898-208125--,00.html

29 NARUC Task Force Webinar 3, State Case Studies. (2010, December 17). *Statutory and Administrative Review of Power Plants in Michigan.* Greg White, Commissioner, Michigan Public Service Commission. Available at: http://www.naruc.org/Publications/White_%20Michigan%20Coal%20Plant%20Review%20Processes.pdf

30 Refer to: Consumers Energy. (2011, December 2). Consumers Energy Announces Cancellation of Proposed New Coal Plant, Continued Substantial Investments in Major Coal Units, Anticipated Suspension of Operation of Smaller Units in 2015. [Press release]. Available at: http://www.consumersenergy.com/News.aspx?id=5167&year=2011

31 Farnsworth, at supra footnote 1.

32 Cause No. PUD 201100077, "In Re: Inquiry of the Oklahoma Corporation Commission to Examine Current and Pending Federal Regulations and Legislation Impacting Regulated Utilities in the State of Oklahoma and the Potential Impact of Such Regulations on Natural Gas Commodity Markets and Availability in Oklahoma."

In response, one participant, Sierra Club, proposed that the Oklahoma Corporation Commission adopt "Integrated Environmental-Compliance Planning."[33] This is an approach that, in many ways, works like an IRP. It considers supply-side, demand-side, and delivery options in an integrated manner. It focuses, however, more closely on the requirements of forthcoming public health and environmental regulations and the imminent need to take actions such as retiring, retooling, or investing in new resources. Whether a commission uses IRP or integrated environmental-compliance planning, reviewing investments in an *integrated* manner is the key. According to Sierra Club, this approach will help ensure a greater understanding of all options available that might otherwise be missed with a narrower approach:

> *Responding to these requirements piecemeal will result in inefficient and unnecessarily expensive decisions. The sheer number and wide coverage of these pending rules mandates that the Commission and the utilities consider their potential impact in a comprehensive, rather than case-by-case basis, for both planning and cost recovery. The Commission should expect to see the anticipated costs and the potential risks of existing and emerging regulations for the whole range of pollutants in utility evaluations of their investment proposals. Given the capital-intensive and long-lived nature of investments in the electric industry, if the final form or timing of a regulation is unknown, the analysis should include both an expected value of the cost of compliance and the range of plausible costs.*[34]

Oklahoma's process initially looks much like an NOI that any administrative agency around the country might undertake. However, one key difference is that the Oklahoma Corporation Commission asked upfront whether its existing planning process is capable of addressing these issues. As noted in the discussion of the Colorado Clean Air – Clean Jobs Act, an inquiry such as this opens up the possibility of a state- or region-wide view of alternatives.[35] Oklahoma and other states could potentially use a process like the proposed integrated environmental compliance planning process to develop resource plans that meet 111(d) requirements, ozone requirements, and the like.

Midwest Independent System Operator Analysis[36]

The Midwest Independent System Operator (MISO) conducted an analysis of potential effects of EPA regulations on its system. MISO's analysis was broken into three phases. Using the Electric Generation Expansion Analysis System model, MISO's first step looked at the effects of several EPA regulations on generation in MISO from a regional perspective. Using results from the first phase, MISO's next step focused on energy and congestion impacts in the MISO system, using a production cost model and transmission adequacy model.[37] In the third phase, MISO developed compliance and capital cost requirements, and analyzed system adequacy, system reliability, and impacts on customer rates.[38]

The MISO process offers an example of how states served by an ISO or RTO might engage their respective ISO or RTO to help assess the potential effects of GHG emissions-reduction policy options on state and regional electricity grids. ISOs routinely use and have great familiarity with electricity dispatch models. Such models require training and a license; gaining competency in these models can be expensive for a single state. However, states can work with their regional ISO to develop inputs and assumptions about various policy options, and the models can be run by the ISOs.

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33 See: Comments of Sierra Club in "In Re: Inquiry of the Oklahoma Corporation Commission to Examine Current and Pending Federal Regulations and Legislation Impacting Regulated Utilities in the State of Oklahoma and the Potential Impact of Such Regulations on Natural Gas Commodity Markets and Availability in Oklahoma," Cause No. PUD 201100077. (2011, July 18). Available at: http://imaging.occeweb.com/AP/CaseFiles/03000E8D.pdf

34 Ibid.

35 There are other notable examples that are not described in detail here. See, for example: Iowa Utilities Board Docket NOI-2011-0003, "Utility Coal Plant Planning," a process designed to gather "Information Related to the Potential Impact of the New EPA Regulations on Iowa Generation Plants." Available at: https://efs.iowa.gov/efs/ShowDocketSummary.do?docketNumber=NOI-2011-0003

36 This discussion is based on a MISO analysis entitled: *EPA Impact Analysis: Impacts From the EPA Regulations on MISO.* (2011, October). Available at: https://www.misoenergy.org/_layouts/miso/ecm/redirect.aspx?id=119399

37 Respectively, the PROMOD IV production cost model and the PSS/E transmission adequacy model.

38 In addition to the aforementioned models, in analyzing system adequacy, MISO also used GE-MARS model.

The MISO process recognized:

- The role of market dynamics;
- That gas prices relative to coal are a key driver; and
- The importance, for scheduling purposes, of knowing when a plant will need to go offline (whether permanently or for retrofitting), and that this can be modeled but that it also needs to be ascertained plant-by-plant from utility companies.

4. GHG Emissions Reductions

As stated earlier, the goal of an IRP is to identify the mix of resources that will minimize future energy system costs while ensuring safe and reliable operation of the system.[39] The goal is not to specifically reduce GHG emissions. However, compliance with current air pollution regulations will normally be established as a condition that must be met before any resource portfolio or action plan is approved. The process can also give due consideration to possible future GHG regulations, such as those proposed by the EPA in the Clean Power Plan. Proposed regulations, as well as a range of possible future regulations, can be included among the base case modeling assumptions or tested as alternative scenarios. The modeling can also test the sensitivity of results to unknown compliance costs, for example, the future cost of an emissions allowance under a trading program. In summary, the IRP process can help a state assess a range of possible policies that can effectuate GHG emissions reductions, while studying their influence on electricity reliability and their costs.

How might a utility prepare an IRP today in a way that helps state air regulators evaluate options and develop a plan for complying with the EPA's proposed GHG rules for existing electric generating units (EGUs)? To begin with, the IRP could specifically include the GHG emissions rate targets proposed by the EPA out to 2030 (or equivalent mass-based limits) as boundary conditions that must be met by any approvable resource plan. The rest of the planning process might proceed as it normally would, but the process would be iterative if the studied resource portfolios failed to comply with the emissions limits.

Alternatively, a default or baseline scenario could be developed based on the mix of resources assumed by the EPA when it developed the proposed emissions rate targets for the state (i.e., the four "building blocks" that the EPA included in its determination of the best system of emissions reduction). Alternative resource portfolios could then be developed and analyzed to see if compliance could be achieved through less expensive means. For example, the EPA assumes in "building block 4" that states will ramp up their existing energy efficiency programs at an annual energy savings rate of 0.3 percent each year until the end goal of 1.5-percent annual energy savings is met. The EPA also posited a ramp rate of 0.5 percent per year as a possible alternative. A third possibility would be to assume zero increase in energy efficiency programs. These three alternatives could be tested (in conjunction with alternative mixes of supply-side resources) in pursuit of a least-cost compliance plan. Similar thinking could be applied to the other building blocks in the 111(d) rule:

- **Heat Rate Improvements.** The IRP could identify affected EGUs, and develop short-, medium-, and long-term assumptions for the timing to complete heat rate improvements, and the potential heat rate improvement for each EGU.
- **Re-dispatch.** The IRP could identify affected natural gas EGUs and develop low, medium, and high assumptions on how quickly these units can reach the requisite capacity factors provided for in the EPA 111(d) rule.
- **Renewable and Nuclear Energy Generation.** For renewable energy generation, the ramp rate assumptions could be analogous to the process used for energy efficiency programs. For nuclear, it could be assumed that future generation will be available at the same rate. A "worst case" assumption of a nuclear unit closing or being shut down would reveal gaps in GHG emissions reductions for that time period and would help a state to plan ahead, as the EPA is proposing that states would have to address GHG emissions gaps that are ten percent or greater in any particular year.

Electricity is often transmitted across multiple states, so the IRP process can also be used by states seeking to develop regional plans to comply with 111(d) requirements. The IRP process can also be used to communicate assumptions and their influence on a regional transmission and distribution system. Where applicable, the appropriate ISO or RTO can work with stakeholders and the utilities to

39 US EPA. (2014). *Survey of Existing State Policies and Practices that Reduce Power Sector CO_2 Emissions.* Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/existing-state-actions-that-reduce-power-sector-co2-emissions-june-2-2014_0.pdf

share assumptions, and evaluate potential regional impacts of various compliance options that are being considered.[40]

5. Co-Benefits

An IRP can simultaneously consider and provide results for many energy, economic, and environmental variables. For example, and as noted in the example from Colorado, an IRP or similar process can reveal cost-effective strategies for addressing multiple air pollutants simultaneously. One scenario that forward-looking states might wish to develop as part of an IRP exercise is to evaluate the effects of the four building blocks in the EPA's 111(d) proposal not only for their GHG emissions impacts, but also for NO_X and SO_2 emissions. This could be particularly important in light of the fact that the EPA proposed to revise the ozone National Ambient Air Quality Standards in November 2014. Depending on the outcome of the rulemaking process, the ozone standard could be tightened to a level that will create many new non-attainment areas and require many areas to develop ozone SIPs again – or for the first time. The timing may be such that states are working on 111(d) compliance plans and SIPs simultaneously, and a coordinated planning approach could reveal cost savings over a pollutant-by-pollutant approach.

In some western states, the IRP process has been enhanced in recent years to more explicitly consider water quantity issues. PUCs in Arizona and Colorado, for example, are requiring utilities to provide data about the water needs associated with meeting electric demand and any vulnerabilities or risks that may be associated with possible droughts or water price increases.

Environmental issues are not the only issues that can be illuminated through smart planning processes. At its core, the IRP process is designed to protect reliability and contain costs for consumers and society. A wide range of co-benefits can be realized through a sound utility resource planning process. The co-benefits of a process that follows the recommendations noted earlier in this chapter are shown in Table 22-2.

Table 22-2

Types of Co-Benefits Potentially Associated With Integrated Resource Plans

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Maybe
Nitrogen Oxides	Maybe
Sulfur Dioxide	Maybe
Particulate Matter	Maybe
Mercury	Maybe
Other	Maybe
Water Quantity and Quality Impacts	Maybe
Coal Ash Ponds and Coal Combustion Residuals	Maybe
Employment Impacts	Maybe
Economic Development	Maybe
Other Economic Considerations	Maybe
Societal Risk and Energy Security	Maybe
Reduction of Effects of Termination of Service	Maybe
Avoidance of Uncollectible Bills for Utilities	Maybe
Benefits to the Utility System	
Avoided Production Capacity Costs	Yes
Avoided Production Energy Costs	Yes
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	Yes
Avoided Distribution Capacity Costs	Yes
Avoided Line Losses	Yes
Avoided Reserves	Yes
Avoided Risk	Yes
Increased Reliability	Yes
Displacement of Renewable Resource Obligation	No
Reduced Credit and Collection Costs	No
Demand Response-Induced Price Effect	Maybe
Other	

40 The ISO RTO Council, a national organization that represents the RTOs, has offered to serve as a resource to state policymakers to help them to assess various 111(d) compliance options. ISO RTO Council. (2014). *EPA CO_2 Rule: ISO/RTO Council Reliability Safety Valve and Regional Compliance Measurement and Proposals.* Available at: http://www.isorto.org/Documents/Report/20140128_IRCProposal-ReliabilitySafetyValve-RegionalComplianceMeasurement_EPA-C02Rule.pdf

6. Costs and Cost-Effectiveness

Integrated resource planning has been adopted by many utilities and mandated by many states precisely because it seeks to identify cost-effective options for meeting electricity demand, while giving due consideration to risks and uncertainty. Although an IRP process does not in and of itself reduce emissions, where effectively used it can point toward a strategic long-term vision of how to address GHG emissions reduction objectives at lowest costs. Establishing and integrating this routine utility planning framework with federal and state environmental requirements can substantially lower the overall burden of environmental compliance while continuing to satisfy the core power sector goal of providing safe, reliable, and affordable electricity.

The mere process of completing an IRP does not guarantee a cost-effective outcome. The details of the IRP process, as well as the data assumptions, will always matter. But the strength of the process is that it is capable of simultaneously evaluating several different policy options and scenarios and a wide range of supply-side and demand-side resource options. Costs and cost-effectiveness are common outputs from IRP modeling exercises.

Although an IRP process often ranks preferred options by overall utility costs, the least-cost option is not universally selected as the preferred resource portfolio. Risk reduction and avoidance of certain environmental costs are often difficult to quantify with precision, especially when future regulatory requirements are unknown, but these factors can be highly valuable to utilities. In some cases, the utility (or regulators) may prefer a resource portfolio that is not strictly the least-cost portfolio under base case assumptions, but is among the lowest cost portfolios across a broad range of scenarios. This may happen in cases in which the least-cost portfolio under base case assumptions turns out to be very expensive under some of the possible future scenarios.

For state air quality agencies that decide to engage with their utilities and PUC in an IRP process, there are, of course, labor costs associated with such participation. However, similar costs will arise from any of the possible ways in which a state air agency might evaluate policies for inclusion in a 111(d) plan or a SIP. Furthermore, if a state uses the IRP process wisely, following recommendations cited in this chapter, it may be able to address energy, 111(d), ozone, fine particle, and regional haze requirements in a coordinated, cost-effective manner.

7. Other Considerations

Integrated resource planning processes offer an interesting and perhaps ideal platform for states to develop 111(d) compliance plans that are sensitive to the need for reliable, affordable electricity.

Unfortunately, in some cases the timing for the preparation or revision of an IRP or regional utility resource plan may not be coincident with that for the preparation of a state 111(d) plan. Each state has its own requirements as to when IRPs must be prepared, and in some cases, it may be that an IRP is required only when a new capital-intensive resource addition is being considered. In other cases, IRPs are required to be submitted or revised every two or three years. If a utility needs to update its IRP at a time when future GHG reduction requirements are not yet certain, it can still evaluate a range of possible regulatory scenarios and assumptions, as Public Service of Colorado did in the example offered in Section 3. The lack of regulatory and legal certainty is no reason to ignore the possible impacts of proposed rules or rules that may be proposed. Ignoring such possibilities could expose the utility to significant risk if it invests in resources that might cost much more to operate under future GHG regulations.

If a utility is not creating or updating its IRP during the time period when state air pollution regulators need to develop a 111(d) compliance plan, the data contained in an existing IRP should still be analyzed for possible use or reference, especially if the utility has already modeled the impacts of possible GHG regulatory scenarios.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on utility resource planning practices.

- Chernick, P., & Wallach, J. (1996). *The Future of Utility Resource Planning: Delivering Energy Efficiency through Distribution Utilities.* American Council for an Energy-Efficient Economy Summer Study. Available at: http://aceee.org/files/proceedings/1996/data/papers/SS96_Panel7_Paper06.pdf
- Farnsworth, D. (2013, March). *Addressing the Effects of Environmental Regulations: Market Factors, Integrated Analyses and Administrative Processes.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6455

- Kushler, M., & York, D. (2014). *Utility Initiatives: Integrated Resource Planning. American Council for an Energy-Efficient Economy.* Available at: http://www.aceee.org/policy-brief/utility-initiatives-integrated-resource-planning
- Olson, D., & Lehr, R. (2012). *Transition Plan Policies – Lower Risk, Lower Cost Electric Service: Policies Western States Can Build On.* Western Grid Group. Available at: http://www.westerngrid.net/wp-content/uploads/2012/12/Transition-Plan_Policies.pdf
- State and Local Energy Efficiency Action Network. (2011, September). *Using Integrated Resource Planning to Encourage Investment in Cost-Effective Energy Efficiency Measures.* Available at: https://www4.eere.energy.gov/seeaction/publication/using-integrated-resource-planning-encourage-investment-cost-effective-energy-efficiency
- Wilson, R., & Biewald, B. (2013, June). *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans.* Synapse Energy Economics for The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6608

9. Summary

Integrated resource planning is a comprehensive energy planning process routinely used in most states to determine what combination of supply- and demand-side resources are most cost-effective to satisfy multiple and sometimes competing energy, economic, and environmental objectives. IRPs and similar utility resource planning processes can have substantial value for state air agencies that are preparing 111(d) plans and SIPs. The IRP process is ideal for identifying resources and strategies that can simultaneously meet multiple energy and environmental objectives at least cost.

Air quality agencies can engage in the IRP process and contribute ideas and data that improve the process and the results. Air pollution regulators have insights and data relating to regulatory requirements, emissions reduction strategies, and costs of compliance that might not otherwise factor into utility resource planning. In addition, air regulators can seek to ensure that multiple air quality problems (e.g., climate change, ozone pollution, and regional haze) are addressed simultaneously and in a coordinated fashion.