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The Path Along the Ridge: Regional Planning in the Face of Uncertainty

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THE PATH ALONG THE RIDGE: REGIONAL PLANNNING IN THE FACE OF UNCERTAINTY[1]

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The Northwest Power Act[2] responds to the changing circumstances of electric power in the Pacific Northwest by defining policy directions and creating new institutional arrangements for regional power planning.[3] The Northwest Power Planning Council (Council) is the agent of the region in meeting the challenges of planning under the Act.[4] This paper discusses the conceptual framework of regional power planning—a task that confronts a degree of uncertainty and risk without historical precedent.

For a quarter-century, electricity demand grew rapidly in the Northwest, doubling roughly every ten years.[5] This growth was readily met by the low-cost, abundant supply of hydroelectric energy developed by the federal government and Northwest utilities in the Columbia River and its tributaries.[6] Steady growth made for simple planning: build more for a

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Author's note: An earlier version of this article was prepared as a discussion paper in March 1982 and distributed widely in the Pacific Northwest. Numerous written and oral comments on the paper were received, and the Northwest Power Planning Council discussed both the paper and comments on it at the Council's meeting on May 6, 1982. In November 1982 the Council adopted a planning philosophy similar to the one outlined here in its Resource Options Decision Memorandum. This article incorporates the author's responses to earlier comments as well as two major analyses stimulated by the discussion paper: a study of the resource options concept concluded in October 1982 by the Pacific Northwest Utilities Conference Committee; and an analysis commissioned by the Council and carried out by the Battelle Pacific Northwest Laboratories.

1. Many of the concepts discussed here were initially developed in R. Watson, S. Aos, J. Douglass, & P. Downey, Power Planning and Uncertainty (revised version, Feb. 3, 1982) [hereinafter cited as WSEO I], a paper prepared at the Washington State Energy Office. These arguments were later extended in S. Aos, J. Douglass, P. Downey, G. Hill, & R. Watson, The Design and Evaluation of a Flexible Power Plan (July 4, 1982) [hereinafter cited as WSEO II].

2. Pacific Northwest Electric Power Planning and Conservation Act, Pub. L. 96-501, 94 Stat. 2697 (codified at 16 U.S.C. § 839 (Supp. V 1981)) [hereinafter cited as Northwest Power Act].

3. *See* BONNEVILLE POWER ADMINISTRATION, LEGISLATIVE HISTORY OF THE PACIFIC NORTHWEST ELECTRIC POWER PLANNING AND CONSERVATION ACT 41ff & 75ff (1981) [hereinafter cited as LEGISLATIVE HISTORY]. A helpful perspective may be found in E. Redman, A Brief Functional Analysis of the New Northwest Power Act (June 1, 1981) (unpublished memorandum) (copy on file with the *Washington Law Review*).

4. Northwest Power Act, *supra* note 2, § 4, 16 U.S.C. § 839b (Supp. V 1981).

5. *See* K. LEE, D. KLEMKA & M. MARTS, ELECTRIC POWER AND THE FUTURE OF THE PACIFIC NORTHWEST 135 (1980) [hereinafter cited as ELECTRIC POWER].

6. *See generally id.* ch. 2 (discussing sources and uses of electric power in the region).

brighter tomorrow. When the potential of the region's rivers was fully harnessed,[7] it seemed sensible to turn to nuclear[8] and coal: supplies that promised to facilitate further growth at higher—but still reasonable—cost. But, even as the Northwest Power Act was emerging from Congress, the era of steady growth ended, a victim of rising power costs and an unstable economy.

There are no facts about the future: predicting energy demand is an uncertain and risky enterprise. If the growth rate differs by only 0.3% per year from the anticipated rate, the gap between the anticipated load and actual load will amount to the equivalent of a nuclear plant in less than fifteen years.[9] Our present ability to forecast demand falls considerably short of even this 0.3% criterion.[10] It now takes several billion dollars and more than ten years to plan and build a major power plant.[11] The costs to the economy of not having enough power are similarly huge.[12]

The planning problem is thus a daunting one: the *best* one can do with current methods seems to entail major risks of either building too much or

7. There is a relatively small, but perhaps important, quantity of hydropower still to be developed on the mainstem of the Columbia. The possibilities of utilizing this resource within the planning framework developed in this article are discussed in Pacific Northwest Utilities Conference Committee, A Discussion Paper of Resource Options 48–49 (Oct. 1982) [hereinafter cited as PNUCC Options Paper]. A substantial quantity of so-called "small hydro" is available for development on smaller rivers and streams in the Northwest.

8. *See generally* ELECTRIC POWER, *supra* note 5, ch. 3 (describing the Hydro-Thermal Power Program).

9. Power demand in the Northwest in 1980 amounted to approximately 16,600 average megawatts. BONNEVILLE POWER ADMINISTRATION, BONNEVILLE POWER ADMINISTRATION FORECASTS OF ELECTRICITY CONSUMPTION IN THE PACIFIC NORTHWEST, 1980–2000 (FINAL) 28 (July 1982) [hereinafter cited as BPA 1982 FORECAST]. Compare the 1.6% annual average rate of growth estimated in the base case of this forecast to one only 0.3% higher. The BPA projects that by 1995 the demand at 1.6% will be 21,101 average megawatts; at 1.9% growth the demand would be more than 22,000 average megawatts, 900 megawatts higher. The output of a large nuclear power station is conventionally estimated at 60 percent "load factor" (the fraction of the time the plant is delivering its full rated output). For a plant nominally rated at 1000 megawatts, then, 600 average megawatts may be used as a rule of thumb. This figure is smaller than the difference between our two estimates.

10. The BPA forecast uses low, base case, and high forecasts whose average annual growth rates range from 0.9% to 2.4%. BPA 1982 FORECAST, *supra* note 9, at 4–10. These values are based upon judgment. The BPA also judges that there is no more than a 75% probability that actual loads will fall within this range. *Id.* By the year 2000 the low and high forecasts differ by approximately 7900 average megawatts. *Id.* at 28. To gain a sense of the uncertainties involved, consider the fact that a typical coal-fired power plant is rated at 500 average megawatts; such a plant costs roughly $1 billion in 1982 dollars.

11. R. BERNEY, W. BUTCHER, G. HINMAN, R. LEWIS & L. SCHWARTZ, INDEPENDENT REVIEW OF WNP-4 AND WNP-5 (March 15, 1982) (Washington Energy Research Center, Washington State University) [hereinafter cited as WERC FINAL REPORT]. The Final Report states that these two nuclear projects, now terminated, would have taken thirteen years and $12.5 billion to complete. *Id.* at 15, 36.

12. *See generally id.* at 133–37 (discussing imbalances between loads and resources).

too little, with heavy penalties either way.[13] In the image of Dan Evans, chairman of the Power Planning Council, the Northwest is walking along a narrow ridge: we can ill afford missteps, but we cannot see as far as we stride. Thus, developing a regional plan goes beyond selecting resources for acquisition by the Bonneville Power Administration: it must also include thinking about *how* resources should be acquired, together with careful consideration of *what kind* of resources are suitable for responsible planning in the face of uncertainty. This article seeks to stimulate discussion of how to do this better.

I. THE UNCERTAIN ENVIRONMENT

From the late 1940's until approximately 1970, demand for electricity in the United States grew in parallel with the gross national product. This growth reflected the fact that electric power was a good buy. Not only was electricity convenient, but the real cost of supplying power steadily declined, as new technology captured economies of scale.[14] In the Northwest, the dominant resource was (and remains) hydropower, developed on a large scale since the federal government launched Grand Coulee Dam during the New Deal.[15] Northwest hydro projects, built during an era of low construction costs and low interest rates—often backed by the federal government—produced the cheapest electricity in the nation.[16] In this setting, vigorous growth in power production was socially rational: overall economic growth would not be constrained by power shortages; the advance of technology meant that new supplies would lower the average system cost as cheaper sources were brought on line; and the growth of demand in neighboring regions, especially California and the Southwest, provided markets for Northwest surpluses.

As steady economic growth gave way in the 1970's to stagflation and energy crisis, the conditions underlying utility planning changed.[17] Plan-

13. The case of Washington Public Power Supply Systems (WPPSS) Projects 4 and 5 illustrates the difficulties. Fearing the economic consequences of shortage, 88 utilities agreed in the mid-1970's to build two plants now terminated because insufficient demand for their output is anticipated. That termination action itself has become the focus of legal and financial crisis. *See generally* E. CARLSON, J. ELORRIAGA & G. WEYERHAEUSER, A REPORT ON THE ECONOMIC IMPACTS OF THE ALTERNATIVES FACING THE REGION ON WASHINGTON PUBLIC POWER SUPPLY SYSTEM UNITS 4 AND 5, REPORT OF THE GOVERNORS' PANEL (1981).

14. *See* Chapman, Tyrrell & Mount, *Electricity Demand Growth and the Energy Crisis*, 178 SCIENCE 703, 706 (1972).

15. *See generally* C. McKINLEY, UNCLE SAM IN THE PACIFIC NORTHWEST ch. 4 (1952) (discussing history of BPA in the Northwest); R. BESSEY, PACIFIC NORTHWEST REGIONAL PLANNING — A REVIEW (1963) (Bulletin No. 6, Division of Power Resources, Washington Department of Conservation).

16. *See* ELECTRIC POWER, *supra* note 5, at 31.

17. *See* Willrich, *The Electric Utility and the Energy Crisis Part I*, PUB. UTIL. FORT., Jan. 2, 1975, at 22–28; and *Part II*, PUB. UTIL. FORT., Jan. 16, 1975, at 25–34.

ning should have changed too, but it lagged,[18] with serious consequences for utilities and their ratepayers. Seven conditions now shape the future:

1. Federal sponsorship[19] remains limited in reach. Despite the regional authority[20] to acquire resources under the Act, the initiative still rests with utilities, local governments, and other project sponsors.[21]
2. The marginal *cost of power is rising,*[22] but both the cost and the output of a given project remain *uncertain.*[23] The troubles of the Washington Public Power Supply System[24] have drawn attention to rising rates.[25]
3. Conservation entails the stimulation and coordination of activities undertaken by thousands of individuals and firms.[26] The utilities have had relatively little experience with conservation or decentralized sources of supply, and *both planning and regulatory oversight have been hesitant and often confused.*
4. Although the Northwest has a strong tradition of public utility ownership,[27] the *open planning* process created in the Northwest Power Act[28] is unfamiliar and uncomfortable for the utilities, especially during the period of adjustment to the institutional arrangements and processes created in the Act. Openness and a complex agenda make the planning process difficult for the Council to manage as well.

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18. *See generally* ELECTRIC POWER, *supra* note 5, chs. 3–5 (describing events leading up to the Northwest Power Act).

19. The principal statements are the Bonneville Project Act of 1937, 16 U.S.C. § 832 (1976 & Supp. V 1981), and the Pacific Northwest Federal Columbia River Transmission System Act, 16 U.S.C. § 838 (1976 & Supp. V 1981).

20. *See* Northwest Power Act, *supra* note 2, § 6, 16 U.S.C. § 839d (Supp. V 1981).

21. *Id.*

22. *See* WERC FINAL REPORT, *supra* note 11, at 84.

23. *See* ELECTRIC POWER, *supra* note 5, at 111–13. Costs are uncertain because of difficulties in accurately estimating construction costs, overruns, and delays; the cost of fuel; expenses for operations and maintenance, especially for new technologies; tightening environmental control obligations (such as waste disposal, decommissioning, or advanced pollution control equipment); and the expense of replacement power in the event of unforeseen outages or fuel-supply interruptions.

The amount of power produced by a project is also subject to uncertainties: a project may fail to be completed or to be operated (a so-called "dry hole"); it may produce less power than planned; or it may encounter unanticipated forced outages.

24. For an independent analysis of the situation facing WPPSS Projects 4 and 5, see the study commissioned by the Washington State Legislature, WERC FINAL REPORT, *supra* note 11; Lee, WPPSS 4 and 5: The agony and the legacy (Part I), The Weekly (Seattle), May 12, 1982, at 2, col. 1; (Part II), The Weekly (Seattle), May 19, 1982, at 2, col. 1.

25. Note that the projected average rate increases are modest in real economic terms (WERC FINAL REPORT, *supra* note 11, at 22) but political reaction reflects instead the large size of the nominal increases in rates.

26. *See* Lee, *Regional Electric Power and Local Governments,* 9 WASH PUB. POL'Y NOTES 4 (Autumn 1981).

27. *See generally* ELECTRIC POWER, *supra* note 5, chs. 2 & 3 (describing the history of the public power movement in the Pacific Northwest).

28. *See* Northwest Power Act, *supra* note 2, § 4, 16 U.S.C. § 839b (Supp. V 1981).

5. Forecasting demand[29] *has become extraordinarily difficult.*[30] Where the smooth and rapid growth of the 1950's and 1960's allowed planners simply to extrapolate historical behavior, the period beyond the mid-1970's continues to be elusive, despite ever more sophisticated methods of analyzing past demand patterns.[31]

29. It is important to bear in mind that definitions of forecasts differ. The Council's forecast, pursuant to the Northwest Power Act, *supra* note 2, § 4(e)(3)(D), 16 U.S.C. § 839b(e)(3)(D) (Supp. V 1981), will be a projection of electric power sales for the 20-year period commencing April 28, 1983, explicitly taking into account conservation programs already underway and cogeneration. Conservation induced by projected increases in rates will be treated as an addition to the supply of power. Variations in the treatment of conservation and cogeneration have led to substantial confusion in the interpretation of forecasts, including the ones developed by the BPA and the Washington Energy Research Center.

30. The uncertainties in forecasting are traceable to two causes. First, there is now greater uncertainty in projecting economic trends, a result of uneven macroeconomic performance in the last dozen years, together with a continued increase in mobility, which has made demographic projections less reliable. Second, the Pacific Northwest is experiencing rapidly rising utility rates, after more than half a century of electric prices that decreased in real economic terms. The response of ratepayers to rising rates is likely to be both significant and complex over the next several years; the character and magnitude of reactions to increasing real prices is not well understood at the national level, not to mention the Northwest region. *See* Northwest Power Planning Council, Economic and Demographic Assumptions 2–5 (Revised Draft, Dec. 10, 1982).

A major consequence of these uncertainties is that the input assumptions in long-range forecasts cannot be estimated with satisfactory precision. At best, then, the information base from which the analyst begins can only produce an estimate of the likely range of future demands, as described in the text. Moreover, when the estimates are imprecise, a regional plan limiting the discretion of the Bonneville Power administrator to make regional power investments (as set forth in the Northwest Power Act, *supra* note 2, § 4(d)(2), 16 U.S.C. § 839b(d)(2) (Supp. V 1981)) becomes, *faute de mieux*, a form of regional economic plan.

The challenge of the Northwest Power Act can therefore be framed in the following terms: the Council must attempt to set investment priorities in conservation and electric power development which will facilitate—rather than direct or circumscribe—the overall economic evolution of the region in response to private initiative, market forces, and policies set by duly constituted governmental authority.

The Council's choices of economic and demographic assumptions are set forth in Northwest Power Planning Council, Decision Memorandum, Economic and Demographic Assumptions (Oct. 13, 1982). For a critique of economic efficiency as a target of energy planning, see Winner, *Energy Regimes and the Ideology of Efficiency*, in ENERGY AND TRANSPORT: HISTORICAL PERSPECTIVES ON POLICY ISSUES 270–76 (1982).

31. It is instructive to examine the track record of the Pacific Northwest Utilities Conference Committee (known as the "West Group" prior to passage of the Northwest Power Act), which publishes annual 20-year forecasts for the Bonneville service area. The West Group forecasts for 1969–1980 are compared with actual average loads in WERC FINAL REPORT, *supra* note 11, at 77; a similar compilation, covering the years 1965–75, is presented in BONNEVILLE POWER ADMINISTRATION, THE ROLE OF THE BONNEVILLE POWER ADMINISTRATION IN THE PACIFIC NORTHWEST POWER SUPPLY SYSTEM IV-84 to -85 (July 22, 1977) (Draft Environmental Statement). These tables demonstrate several interesting tendencies: (1) Since the 1969–1970 operating year (and in a majority of cases earlier as well) the PNUCC forecasts have consistently projected larger loads than actually occurred. (2) The magnitude of the overestimates increased beginning in the 1973–1974 year, regularly reaching more than 10 percentage points in the late 1970's. (3) There is a weak tendency for the size of the overestimate to correlate with regional economic conditions in the year forecast was made. (I am indebted to H.M. Mozer for bringing these data to my attention, and for pointing out the third of these trends.)

6. *Large, capital-intensive resource projects now pose substantial risks.* Costs and schedules have been difficult to control.[32] Moreover, with the slowing of load growth, arrangements for fully utilizing large facilities have become unexpectedly important.[33]
7. A consequence of the last two points is that commitments to large resources a decade or more in advance—standard practice now—are no longer tenable without substantial change.

Despite the explosion of uncertainty—indeed, because of it—it is more urgent than ever *to plan and to share risks regionally*.[34] A central feature of the Northwest Power Act is the ability to plan a cost-effective mix of resources on a regional basis.[35] The uncertainties listed above imply a need for regional risk management as well—a process for insuring *long term cost-effectiveness* in the face of uncertainty.

II. PRINCIPLES FOR MANAGING RISK

Regional planning can be organized around eight principles, several of which are drawn directly from the Northwest Power Act. These principles form a coherent framework for dealing with the uncertainties facing the Pacific Northwest. To facilitate exposition, they are first listed briefly:

1. In place of deterministic planning, there should be a regional risk-management process[36] that stresses *flexibility*.
2. In particular, the planning process should prepare the region to meet *a*

The second trend, the increase in error since 1973–1974, may be traceable to the fact that firm sales of hydropower from the Federal Columbia River Power System to the investor-owned utilities of the Northwest ended in 1973. As a result, rates paid by consumers served by investor-owned utilities began to rise that year. With the rise in rates, consumption dropped, and the size of this change may have eluded forecasters. *See* THE WPPSS INDEPENDENT STUDY STEERING COMMITTEE, AN EVALUATION OF THE WASHINGTON ENERGY RESEARCH CENTER'S FINAL REPORT, INDEPENDENT REVIEW OF WNP-4 AND WNP-5, at 6–11 (Mar. 26, 1982); Economic and Demographic Assumptions, *supra* note 30, at 2–5.

32. For a careful analysis of the components of cost in generating stations, see P. HILL, POWER GENERATION (1977); I WASHINGTON STATE SENATE ENERGY AND UTILITIES COMMITTEE WPPSS INQUIRY, 47th Leg., CAUSES OF COST OVERRUNS AND SCHEDULE DELAYS ON THE FIVE WPPSS POWER PLANTS (1982); WASHINGTON ENERGY RESEARCH CENTER, COSTS AND SCHEDULES. MODULE III FINAL REPORT (Jan. 1982).

33. *See* WASHINGTON ENERGY RESEARCH CENTER, MARKETS FOR IMPORTS OF ELECTRICITY, MODULE IV FINAL REPORT (Jan. 1982).

34. *See* Lee, *Electricity: Toward a Regional Strategy*, in ENERGY POLICY AND PUBLIC ADMINISTRATION (1980).

35. Northwest Power Act, *supra* note 2, § 4(e), 16 U.S.C. § 839b(e) (Supp. V 1981).

36. The utilities' appraisal of this approach is contained in PNUCC Options Paper, *supra* note 7. The argument of this article accords with their conclusion: "The electric utility industry is well aware of the need for greater flexibility in the planning and construction process. A well designed and workable options process would be highly welcome." PNUCC Options Paper, *supra* note 7, at 2.

wide range of loads in all the years encompassed by the plan, instead of relying upon a most-likely demand forecast.[37]

3. The regional plan should *shift the burden of risk* from individual project proponents *to the region as a whole,* as a form of regionwide insurance.[38]

4. The Act establishes fundamental priorities for resource planning:[39] *to minimize expected cost,* while giving priority, first, to conservation; second, to renewable resources; third, to resources utilizing waste heat or generating methods of high fuel conversion efficiency; and fourth, to "all other resources."[40]

5. The Northwest Power Act also creates an institutional structure for *decentralized implementation of a centrally written plan.*[41]

6. In place of the conventional bias toward economies of scale in power generation, planners should search for cost-effective combinations of conservation and resources that can provide planning flexibility. When comparing projects that are *equally costly* to the region, those available on short notice should be given priority over those with long lead-times; small projects should be preferred to large ones; and programs that can be slowed, halted, or reversed should be more useful than those entailing inflexible commitments.

7. The planning process should manage the burdens of financing, licensing, and institutional change by making regional commitments on a schedule that reflects the slower load growth that characterizes a period of rising real rates.

8. The integrated hydro system has been augmented with thermal generation developed on a piecemeal basis. The Northwest Power Act—and the risk-management approach in particular—implies a *substantially more complex* regional power system,[42] one encompassing activities and actors unfamiliar to the utility community.[43] The challenge of this additional complexity must be taken seriously in the planning process.[44]

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37. *See supra* notes 30–31 (discussing limited accuracy of forecasting).

38. As the number of participants in a project increases, the risk to the collectivity decreases, since adverse outcomes will be more widely shared. For the economic theory putting this concept on a rigorous foundation, see Arrow & Lind, *Uncertainty and the evaluation of public investments*, 60 Am. Econ. Rev. 364 (1970).

39. Northwest Power Act, *supra* note 2, § 4(e)(1), 16 U.S.C. § 839b(e)(1) (Supp. V 1981).

40. *Id.*

41. Section 4(e)(2) of the Act authorizes central planning by the council. *Id.* § 4(e)(2), 16 U.S.C. § 839b(e)(2). Section 2(5) expressly foreswears limits or restrictions upon the freedom of utilities and maintains "the authorities and responsibilities of State and local governments, electric utility systems, water management agencies, and other non-Federal entities." *Id.* § 2(5)(A), 16 U.S.C. § 839(5)(A).

42. *See* PNUCC Options Paper, *supra* note 7, at 3.

43. The technological implications of increased complexity are addressed, in part, by a System Analysis Model being built by a committee of the Pacific Northwest Utilities Conference Committee.

The paradox of regional planning and decentralized execution can be resolved in two somewhat different, but complementary, ways.[45] First, there should be liberal use of markets and market-like incentives.[46] Second, the plan and planning process should be instruments of political leadership, articulating purposes[47] and mobilizing the energies of the diverse interests whose partly independent activities constitute the implementation of the plan. Decentralized execution will not be easy to achieve, but there is an important opportunity for Council leadership in the fact that the economic interests of the region parallel the goals of the Act.

The shift from deterministic planning to regional risk management is fundamental. This article focuses on planning, but a flexible approach implies significant changes in the way that projects are developed and

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This model estimates the interactive effects of adding new supplies, such as renewable resources, to the existing regional hydro system. The System Analysis Model is an outgrowth of a long tradition of technical cooperation among the region's utilities, a relationship specified in the Pacific Northwest Coordination Agreement of 1964. On the Coordination Agreement, see ELECTRIC POWER, *supra* note 5, at 54–55.

It remains to be seen, however, whether this technical level of cooperation can be extended to non-utility actors such as industrial firms undertaking cogeneration, and whether technical cooperation can foster institutional collaboration. It is a hopeful sign, accordingly, that the use of the System Analysis Model for regional planning is discussed in PNUCC Options Paper, *supra* note 7, at 23–27.

44. There are two critical differences in regional power planning under the Act. First, financing of a major resource may be accomplished through acquisition of its capability by the Administrator of BPA, pursuant to authority granted him under § 6(a), (d), (e), (f), (h), & (l), 16 U.S.C. § 839d(a), (d), (e), (f), & (l) (Supp. V 1981). But second, authorization for acquisition depends upon designation of that resource in the Northwest Power Planning Council's regional energy plan, in accordance with the process set forth in § 4(d)–(g), 16 U.S.C. § 839b(d)–(g) (Supp. V 1981); the Administrator's authority is further subject to the constraints outlined in § 6(b)–(m), 16 U.S.C. § 839d(b)–(m) (Supp. V 1981). These new arrangements create a major financing role for the BPA, extending, perhaps a great deal, the possibilities devised under the rubric of "net billing" in the 1968 Hydro-Thermal Power Program. *See generally* ELECTRIC POWER, *supra* note 5, ch. 3 (discussion and explanation of net billing). Moreover, a new set of actors, state governments acting through their representatives on the Council, effectively controls access to the regional financing mechanism. These two principal changes affect the independence with which utilities may plan their own activities by altering the financial and organizational incentives for joint action in response to expectations of future power demand. The Northwest Power Act affects utility planning in other significant ways as well, notably through its requirement for a fish and wildlife program in the Columbia River basin.

45. *See generally* ELECTRIC POWER, *supra* note 5, ch. 7 (analyzing conceptual approaches to regional planning).

46. *See generally* C. SCHULTZE, THE PUBLIC USE OF PRIVATE INTEREST (1977) (advocating use of market arrangements to implement public policy).

47. *See* P. SELZNICK, LEADERSHIP IN ADMINISTRATION (1957) (emphasizing the role of purposes in organizational management).

programs managed. Regional risk management also requires coordination of operations with planning,[48] in order to permit adjustment of both plans and operational policies to respond to emerging conditions.[49]

The broad ramifications of a risk-management philosophy should not obscure its essential simplicity, however. Faced with uncertainty, the planner seeks two critical attributes: diversification[50] and the ability to adapt to changing conditions. Flexibility and diversity are well-accepted notions in finance, where the sharp economic fluctuations of the past decade have underscored their value.

A planning concept that provides flexibility in the utility context is the *resource option*.[51] The Act provides a mechanism for regional acquisition of conservation and generating resources.[52] A resource option is an acquisition contract that explicitly provides for *regional* control of the timing and magnitude of the project.

It is important to distinguish our use of the word "option" from the similar-sounding term "option to purchase [a share of a generating project]" commonly used in the utility industry. In this article, an option is a contract between the administrator of BPA and a project proponent which

48. For example, the regional energy plan now being developed by the Council will be adopted in April 1983 (executing the mandate of § 4(d)(1) of the Northwest Power Act, *supra* note 2, 16 U.S.C. § 839b(d)(1) (Supp. V 1981)), after the adoption in November 1982 of a program "to protect, mitigate, and enhance fish and wildlife" in the Columbia River and its tributaries. *Id.* § 4(h)(1)(A), 16 U.S.C. § 839b(h)(1)(A). A flexible energy plan affects and interacts with the fish and wildlife program: changes in one influence choices in the other. In part for this reason, the fish and wildlife program adopted by the Council contemplates studies and revisions of the program. As information on the implementation of that program accumulates, corresponding modifications of the energy plan may also be appropriate. Thus, the complexity of the planning task set forth in the Northwest Power Act itself points to the wisdom of a flexible approach to planning, so that new information can be incorporated in decisionmaking.

49. Note that the utilities explicitly reserve judgment on the operational implications of a risk-managing approach to planning. PNUCC Options Paper, *supra* note 7, at 2.

50. For an economic analysis of diversification, see Tobin, *The Theory of Portfolio Selection*, in THEORY OF INTEREST RATES (1965).

51. *See* Northwest Power Planning Council, Resource Options Decision Memorandum 2 (Nov. 30, 1982) [hereinafter cited as Options Memorandum]:

> For the purposes of power planning, options will be investments by the Region in the early phases of resources development or investments in the early completion of a resource that can be sold outside of the region with call back provisions. The Region will receive in return for this financial assistance the right to exercise the option and provide additional energy to meet load growth with shorter lead-time and higher confidence or to hold the option and delay the acquisition of additional energy.

For a helpful analysis of options using information relevant to the Pacific Northwest, see E. MOORE, JR., R. WATTS. B. HARRER & P. HENDRICKSON, DEVELOPMENT AND SUPPLY RESOURCE PLANNING OPTIONS (1982) (Report submitted by Battelle Pacific Northwest Laboratories to the Northwest Power Planning Council) [hereinafter cited as BATTELLE OPTIONS STUDY]. This analysis identifies three or four "cost nodes" at which project costs and schedules can be readily evaluated by regional decision makers. *Id.* at 6.1–.6.

52. Northwest Power Act, *supra* note 2, § 6, 16 U.S.C. § 839(d) (Supp. V 1981).

reserves to the administrator certain rights to alter the schedule on which the project is built or implemented. This contract also spells out a timetable for payments to the project sponsor from BPA, payments to meet the costs of the project as well as certain of the opportunity costs borne by the project sponsor.[53] In some instances, the lead-time for undertaking a project is a good deal shorter than the period between the present and the date at which the resource is expected to be a cost-effective element of the regional power supply. Resources meeting this combination of criteria, so-called "planned options,"[54] can be scheduled in the Council's plan without a corresponding effort by BPA to initiate a contract for acquisition. These planned but not yet purchased options should, in general, be treated as less definite resource alternatives than projects for which a contract has been signed.

In order to be usable in planning, an option can be *no less real than any other resource* in the plan.[55] The experience of the last fifteen years indicates that resource plans regarded by the utilities as "real" cannot be counted on.[56] If the regional planning process cannot improve upon this

53. "An option is an agreement between a potential buyer and seller of a property, good or service in which, typically, the potential buyer pays cash or other consideration to [the] seller for the right to buy the property, good or service within a particular time on specified terms." Options Memorandum, *supra* note 51, at 2. Identical wording is used to define "option" in PNUCC Options Paper, *supra* note 7, at 1.

54. WSEO II, *supra* note 1, at 3; PNUCC Options Paper, *supra* note 7, at 4.

55. The PNUCC Options Paper, *supra* note 7, describes five general categories of resource options, distinguishing among them on the basis of how readily available each set is likely to be. "Ready resources" like combustion turbines are available "off the shelf" on short lead-times and with minimal licensing delays. "Sales/import options" are contractual arrangements with owners of facilities, providing either rights of purchase (for resources outside the Northwest) or sales (to out-of-region customers) subject to rights of recall under specified conditions. "Purchased/licensed options" have obtained relevant regulatory clearances; the holder of the option thus controls the timing of progress on these projects. "Purchased/unlicensed options" are projects that have been included in the plan, but which still face state and federal licensing procedures. Least reliance should be placed in the fifth category, planned options of the kind described in the text. PNUCC Options Paper, *supra* note 7, at 4–5. (Compare the five generic types of options identified by the Council, *see infra* note 65.)

The PNUCC suggests that a regional policy be developed to "identify those types of resources which are firm enough to be considered for optioning." PNUCC Options Paper, *supra* note 7, at 10.

Note that this categorization is most clearly applied to conventional generating resources. Conservation is in part a "ready" resource, capable of being implemented rapidly, and in part a "planned option," insofar as the conservation program is novel and untried on a large scale. WSEO I, *supra* note 1, at 8.

56. The best known example is the schedule slippages in the nuclear projects of the Washington Public Power Supply System. *See* sources cited *supra* at note 24. These are not the only cases of significant disparity between initial plans and actual performance in power plant construction, however. The Skagit nuclear project and two units of the Colstrip coal-fired project sponsored by Puget Power have suffered lengthy delays. Similar difficulties have plagued Portland General Electric's Pebble Springs nuclear project.

record,[57] one of the main hopes in the Northwest Power Act will have been dashed. Thus, if there are unresolved technical questions, such as the feasibility of stack-gas scrubbers on coal plants,[58] a credible research and development program should be underway to settle them. If there are uncertainties in cost and schedule, these must be managed on the same basis for an option as for an acquired resource.[59] If there are institutional hurdles, such as approval of a site by a state licensing authority, these must be addressed in a timely fashion whether the project is an option or an acquired resource.[60] In short, a resource option should be no different from an acquired resource *except* in the way it is handled by the BPA and the Council.

An option is treated differently by the region in two respects. First, the option agreement would authorize BPA and the Council to accelerate, delay, or cancel the project, as part of a cost-effective regional power program. The early stages of developing a conservation program or generating resource are typically far less costly than the construction or implementation phase,[61] while taking up a sizable fraction of the total time needed for development.[62] An option agreement might therefore schedule

57. The PNUCC Options Paper, *supra* note 7, recommends that the Council and the BPA endorse requests for flexibility by utilities and other resource sponsors. *Id.* at 8–9 & 46–47. Such a posture seems sensible in general, although each proposal, regarded as either a resource or a planning option, needs to be evaluated on its merits.

58. For a discussion of the technical problems of coal power plant gas scrubbers, see Ackerman & Hassler, *Beyond the New Deal: Coal and the Clean Air Act*, 89 YALE L.J. 1466 (1980).

59. A project whose schedule can be changed by regional authorities may encounter difficulties in maintaining a high-quality work force. PNUCC Options Paper, *supra* note 7, at 10. The timing of schedule changes is accordingly important.

60. Options thus become a significant new rationale in the utilities' pursuit of regulatory relief. PNUCC Options Paper, *supra* note 7, at 13–15.

61. In a review of cost estimates for a wide spectrum of conservation and generation alternatives, the BATTELLE OPTIONS STUDY, *supra* note 51, concludes that "for all resources except geothermal and nuclear, acquisition costs at any of the specified points before construction are less than 15% of the total capacity costs." *Id.* at 6.7. Costs for geothermal are high near the beginning of a project because of the expense of site investigation and preliminary development. *Id.* at 6.35. In any event, the costs of geothermal energy are still uncertain, given the limited field work done in the region to date. Pre-construction costs for nuclear are high because of the expense of detailed safety analyses required by the Nuclear Regulatory Commission, and because the steam supply system is normally procured prior to the start of construction. *Id.* at 6.65–.66.

The cost of delaying development of a project is also modest: if the interruption occurs before construction starts, the cost of the first year of delay is "less than $15 per kilowatt of capacity." *Id.* at 6.7. As delay increases, however, changes in regulation, financing, and other conditions will affect the viability of the project as originally defined. "[A] delay of greater than five years in exercising a resource option will almost certainly necessitate some changes . . . ." *Id.* at ES.22.

62. In a comparison of 15 categories of power resources, the BATTELLE OPTIONS STUDY, *supra* note 51, finds that pre-construction activities account for a minimum of 36% (light-water nuclear reactor) and a maximum of 77% (wind farm) of the total time needed to develop the resource. *Id.* at 5.3. These percentages are substantially larger than the fractional cost commitments of pre-construction activities.

a regional decision on whether to proceed, and how rapidly to do so, before construction begins.

A second way that the region treats an option differently from an acquired resource is that the project sponsor may be compensated for the risk that the project will be rescheduled or terminated. An option is a form of insurance to the region, since it improves the ability of the regional planning process to meet a range of loads.[63] Risk payments to the sponsor are insurance premiums.[64]

Regional resource options are an important means of improving the flexibility of planning, but there are additional ways to do so.[65] For example, existing generating projects can be operated beyond their normal capacity for short periods.[66] Smaller projects and resources available on short lead-times make it easier to respond to changing circumstances. Conservation seems unusually flexible because the size of the resource can be adjusted; if loads grow more rapidly than anticipated, a more aggressive, and expensive, conservation effort can be pursued with little lead-time, if this possibility has been planned for. Renewable resource projects promote flexibility as well,[67] when they are smaller than thermal projects. Some uncertainty remains, however, on two points: the quantity of conservation[68] and renewable resources that can be developed at cost-effective levels; and the credibility of schedules for developing such projects.[69]

It is also worth noting that large central-station plants can be made more flexible through institutional changes, including option arrangements.[70] Obtaining approval for sites and for engineering designs is a

63. WSEO II, *supra* note 1, at 8–15.

64. The Northwest Power Act provides that the BPA may "provide for the reimbursement of the sponsor's investigation and preconstruction expenses." Northwest Power Act, *supra* note 2, § 6(f)(1)(B), 16 U.S.C. § 839d(f)(1)(B) (Supp. V 1981). This language provides a means for authorizing payment for options.

65. The Council has identified five generic types of options for planning: (1) resource options, which are funded on a regional basis up to the point where construction begins; (2) acquisition of a resource, together with a contract for (contingent) sale of the resource outside the region; (3) demonstration projects intended to verify the costs and magnitude of a resource (expected to be of major importance in planning for conservation); (4) resources whose costs of operation can be met through regional purchase (combustion turbines used to meet short term unanticipated demand fall in this class); and (5) rate designs, approved in advance, that can be used to recover temporarily high running costs or to signal imminent scarcity of supply. Options Memorandum, *supra* note 52, at 2, 4.

66. PNUCC Options Paper, *supra* note 7, at 21–22.

67. The utilities judge small hydro and cogeneration to be "[t]he best candidates for an options portfolio of some security." PNUCC Options Paper, *supra* note 7, at 36. The complexities facing the development of cogeneration are discussed in *id.* at 50–56.

68. *Id.* at 40–41.

69. The PNUCC expresses skepticism about geothermal and wind as resource possibilities. *Id.* at 36–39.

70. *Id.* at 39–40.

time-consuming part of a power plant project. If sites and licenses can be approved and then "banked," to be used for full-scale development later, the lead-time for large projects can be substantially shortened.[71] Similarly, marketing part or all the output of a power station to utilities outside the Northwest decreases the effective size of the commitment shouldered by the region.[72] If these marketing arrangements include contingency arrangments, perhaps along the lines of the call-back provisions in the Canadian Storage Power Exchange,[73] both size and timing can be made flexible. Regional control of banked sites and callback options enhances the risk-management capability. Finally, flexible arrangements for providing power in the Northwest may be obtainable from sources outside the region: the spot market in wholesale power; purchase on contract; and power exchange agreements have been used by individual utilities in the past.[74]

In addition, there are institutional arrangements with consumers that can improve planning flexibility. For instance, rate schedules that are implemented only when a shortage looms can be used to hold down demand on short notice,[75] if loads surge unexpectedly or supplies sag.[76] Such contingent rates would require advance approval by public utility commissions, however, to make them usable as regional options. The fact that secure power supply is more valuable to some industrial customers than others[77] can form the basis for a futures market,[78] in which costly resources can be developed on behalf of those willing to bear the risk of paying for them in order to assure supply. Conversely, there may be con-

71. The difficulties of site banking and advance licensing are summarized in *id.* at 42–47.

72. *Id.* at 17–21.

73. *See* ELECTRIC POWER, *supra* note 5, at 55.

74. PNUCC Options Paper, *supra* note 7, at 16–17.

75. *See* WSEO I, *supra* note 1, at 10.

76. Unusually cold winter weather can suddenly increase demand for electric heat, while a period of below-average precipitation in the Columbia basin can decrease supplies of hydropower. Sudden changes in demand or supply have been met in two ways: through out-of-region purchases of wholesale power, with utilities sometimes paying premium prices on the spot market; or through reductions in use, both voluntary and pursuant to BPA's contracts with its direct-service industrial customers. In periods of severe drought, spot market purchases have necessitated rate surcharges, to cover the costs of imported power.

What is suggested here is a means to signal short-run changes in the supply-demand balance via electric rates. The historical experience described above, as well as experience in other regions, indicates that demand can be changed in the short run by up to 10%, through a combination of public appeals and temporary rate adjustments. It is hard to estimate precisely, however, how much of this short-run change can be produced initially and how long the lowering of demand can be sustained.

77. WSEO II, *supra* note 1, at 14.

78. *See* G. Hill, The Public Interest and the Evaluation of Public Policy 288–90 (1981) (unpublished Ph.D. dissertation) (copy on file with the *Washington Law Review*).

sumers willing to purchase interruptible power,[79] who have not had access to lower-quality power in the past; their purchases can provide peak-load reserves and flexibility in planning.

The flexible, risk-managing approach differs from deterministic planning in one important economic respect: risk management does not minimize short-run costs.[80] But if the future is really uncertain, a flexible combination of projects can lead to much lower costs than a least-cost investment that turns out to be based upon mistaken assumptions.[81] The concept of portfolio diversification—not putting all one's eggs in the same basket—embodies the same risk-managing philosophy. A diversified portfolio may not earn the maximum return, but it greatly decreases the probability of substantial losses.[82]

Of course, one can hedge one's bets foolishly as well as wisely. Regional risk management is not self-implementing. But the deterministic approach, in the face of the uncertainties that confront the region, may guarantee failure. Putting these principles into a workable planning process will require technical, organizational, and governmental changes. As a first step it may be sensible to consider a deliberately oversimplified example of how a regional plan could be more flexible.

III. AN EXAMPLE OF FLEXIBLE PLANNING

In conventional utility forecasting the objective is to estimate as accurately as possible the future demand for electric power. A common approach is to make high, low, and intermediate forecasts, using different demographic variables and assumptions about consumer response to rate changes; typically, the intermediate forecast is selected as the planning target.[83] When uncertainty is high, however, there may be *insufficient information to identify an appropriate intermediate case*. That is, the region may have to meet a demand for power ten or twenty years in the future that can lie anywhere within a broad range. It is reasonable to think, however, that one can still identify a broad range within which demand is expected to lie;[84] the question for planning is how to use this information.

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79. For a discussion of interruptible power and its most effective uses, see Redman, *Nonfirm Energy and BPA's Industrial Customers*, 58 WASH. L. REV 279 (1983).

80. *See* WSEO I, *supra* note 1, at 2–3.

81. *Id.*

82. Tobin, *supra* note 50.

83. The PNUCC maintains that "the most probable load forecast" should be used as a planning target. PNUCC Options Paper, *supra* note 7, at 6.

84. *See supra* notes 31–32 and accompanying text (discussing attainable accuracy of forecasts).

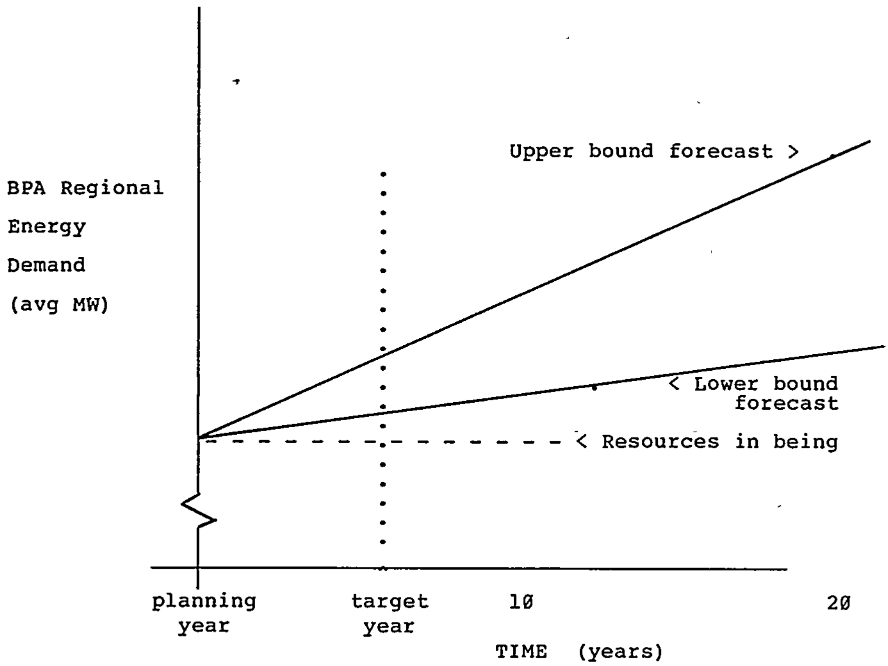

Figure 1. Upper and Lower Bound Forecasts (schematic).

Figure 1 shows a pair of schematic demand forecasts. They are limiting cases, chosen on the basis of a consensus within the forecasting community[85] that actual demand will lie between the lower and upper bound forecasts. Regional risk management proceeds this way:

1. The regional plan must assure that resources are adequate in each year of the planning period to meet the lower bound forecast demand. This requires *resource acquisitions.*

2. The regional plan must also assure that a combination of resources and options is available to meet the upper bound forecast in each year of the planning period. This requires *development and acquisition of options,* as well as resources.

3. In order to be included in the plan, an option must meet standards developed by the Council. These standards should insure that the option can, in fact, be converted into a resource by the year in which it is listed.

4. A regional plan developed in this fashion must be reviewed frequently—perhaps annually—so that the mix of options and resources acquired can be adjusted in light of new information. Important kinds of new information

The BPA 1982 FORECAST, *supra* note 9, was one of the first forecasts in the region to attempt a systematic specification of a range within which demand is very likely to be found.

85. BPA 1982 FORECAST, *supra* note 9, at 21–22.

include changes in the existing power system; revised lower and upper bound forecasts; data on costs and schedules of resources acquired; data on the costs of options and their availability for the year planned; and new resources and options developed since the last review.

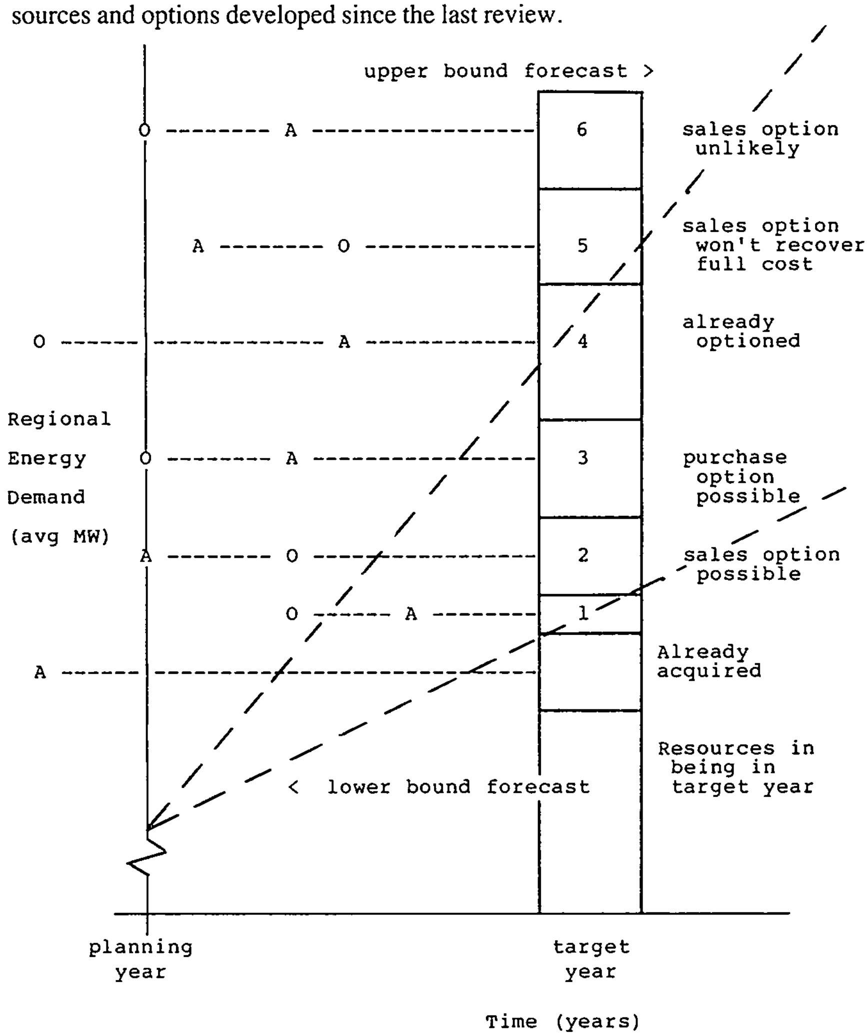

Figure 2. Example of Resource Possibilities for a Target Year, with timing of decisions to option (O) and to acquire (A).

How does one fill in the V-shaped space between the lower and upper bound forecasts?[86] Figure 2 demonstrates an approach for a single target

86. The PNUCC identifies three approaches: 1) a "lower jaw tactic," in which resources would only be acquired to meet the lower bound forecast, with options to fill the gap between the lower and upper bounds; 2) an "upper jaw tactic," relying on sales options to manage excess capacity; and 3) a "between the jaws tactic" in which a "most probable load forecast" is used as the basis of an options approach. PNUCC Options Paper, *supra* note 7, at 6.

year. Looking at the target year from the vantage of the planning year in Figure 2, the planner ranks resource possibilities in order of increasing expected cost.[87] The resource possibilities vary in size, but when assembled they span the range from resources in being—the regional system projected for the target year—to beyond the upper bound forecast.

Lead times for these resources vary. Some projects have already been optioned or acquired in earlier planning years, though more are needed to reach the lower bound forecast. Some projects do not need to be started yet, such as Project 1. In three cases—Projects 2, 3, and 6—a decision must be made in the current planning year. The risk-management process concentrates on these decisions.

Project 1 does not have to be examined in detail, even though, among resources available in the target year, it is expected to be lowest in cost. An acquisition decision has to be made on Project 2, however. Situations like this illustrate the *tradeoff between cost-effectiveness and flexibility*.[88] If Project 2 is acquired, an irreversible commitment will have been made before the region has purchased lower-cost power from Project 1. The dilemma is that the planning process cannot wait for the Project 1 decision point, for Project 2 would no longer be available, and higher cost resources, such as Project 5, might then have to be developed. How should one value Project 2? There is, unfortunately, no simple method for gauging the relative value of flexibility and cost.

For this reason, among others, the design of the regional energy plan is necessarily a task requiring judgment by the Council. Even whether to acquire Project 2 is a choice that can be illuminated through analysis. For example, it is possible to compare the implications of acquisition and deferral of this project. Pulling Project 2 out of the resource stack—the result if the project is not acquired—would necessitate the addition of more resource possibilities, higher in cost than Project 6, so that the range be-

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These analysts misconstrue the argument of this article as one favoring the "lower jaw tactic." PNUCC Options Paper, *supra* note 7, at 5. I argue three related points. First, that the degree of uncertainty is, as a practical matter, too large to permit reliance upon a "most probable load forecast." Second, that a balanced approach to the circumstances facing the region would utilize both resource acquisitions above the lower bound forecast and sales options. But third, that the mix of these alternatives with resource options should be biased toward retaining as much flexibility as affordable, rather than carrying on with the traditional single-forecast framework. My reading of the situation of this region is rooted in the perception that Northwest power supply is not operable as a single utility system; this leads me to emphasize a shift toward flexible planning.

87. This expected cost should include measures of the technical, environmental, and institutional differences among resource alternatives. Some of these factors cannot be measured in monetary terms, however, although they are clearly relevant to a decision. For example, where a given resource is located can affect its accessibility to the regional grid, its financing, and the political acceptability to local populations of proceeding with the project. These factors are put aside in this simplified example. The concept of expected cost is discussed in WSEO II, *supra* note 1, at 8–9.

88. WSEO II, *supra* note 1, at 11–12.

tween lower and upper bound forecasts is still covered. At the same time, deciding not to acquire Project 2 could mean that it remains available for development in a later target year, though probably at higher cost. On the other hand, if load growth falls in the low part of the range, foregoing acquisition can lead to a lower cost regional system.

Note that Project 2 has a decision point for an option *after* it is acquired. This indicates the possibility of a sales option: a contractual agreement with a wholesale power purchaser for sales beginning in the target year. A sales option protects the possibility of selling power at a given price. The sales-option decision can be scheduled just before the bulk of the money is spent on construction, thus providing an opportunity to evaluate progress. If a sales option can be obtained by that time, the region can proceed, knowing that there is an assured market for part of the Project when it comes on line in the target year. At the same time, an option to sell decreases one's flexibility, since the option is likely to include an assurance that the power will be available to sell in the target year. Without such an assurance, the price of the option would probably be so high that the Northwest would gain little from having it.

Project 3, like Project 1, provides the possibility of a *purchase* option: an agreement to initiate a project with regional financing, subject to review at the point labeled "A." The point of no return, economically speaking, occurs soon after the acquisition decision. Project 4 was optioned in an earlier planning year, and the final acquisition decision is still some way off; no decisions need to be made in the current planning year. Note, however, that information obtained since the last planning year may have shifted the costs and schedule of Project 4; its position in the stack may thus be different from a year earlier.

Project 5 is also a resource possibility for which no decision need be made. It is high enough in the cost stack, however, that, on the basis of current information, a future sales option may not allow the Northwest to recover the full cost of the project. This information clearly has a significant bearing on the acquisition decision. Finally, Project 6 requires an option decision in the current planning year. As with Project 2, payment to keep Project 6 available will have to be made this year, despite its relatively unfavorable position in the cost-effectiveness stacking. The questions that arose earlier in the discussion of Project 2 are thus relevant. The answers to these questions may be different, however; both the high expected cost of Project 6 and the fact that a sales option may be difficult to arrange decrease its desirability.

These resource possibilities have been discussed schematically. Important considerations have been slighted in this example, including the geographical location of the projects, how they fit into the priority classes mandated by the Northwest Power Act,[89] and the operational characteristics of the overall resource mix[90] if these projects were to be acquired. These complications matter, of course, and would need to be analyzed in detail, using information developed by BPA, the Council, the utilities, and other project sponsors and analysts.

It must also be stressed that the regional risk management process is a dynamic one. As new information comes in about resources and about the outlook for demand, it should be used to adjust plans and commitments.

Consider what is likely to happen in the next planning year. There is now more information about each target year, though it is still incomplete. Upper and lower bound forecasts have shifted; usually, the distance between upper and lower bounds will have narrowed, since each target year is now closer to the point of the V.[91] Second, the expected resources in being may have changed; changes in one target year affect the resources in being in later years. Third, the costs, sizes, and availability of resource possibilities have changed; projects that have been delayed are no longer available in the original target year. This plethora of alterations illustrates the need for frequent review of the plan.

Regional risk management emphasizes the development of options. Resource possibilities whose costs remain in the cost-effectiveness range spanned by the upper and lower bound forecasts are likely to be acquired at some point, though slow demand growth may delay them for a time. On the other hand, if the economics of power supply change dramatically, an option may be priced out of the evolving market. For instance, federal hydro projects introduced an extremely low cost resource to the Northwest, lowering the cost of electricity substantially; the escalating cost of Projects 4 and 5 of the Washington Public Power Supply System, in contrast, undermined their viability in the regional market.[92]

The risk management approach also uses the information produced by forecasting in a novel way. The stress now lies on using the bounding estimates to define the range of resources and options needed in each target year. The traditional reliance on best-estimate forecasts has meant that high and low cases were selected casually. There is considerable room for improvement in choosing defensible upper and lower bound forecasts. Asking experienced forecasting modelers for consensus judgments on input data[93] is a first step: what is the range within which the population

89. Northwest Power Act, *supra* note 2, § 4(e)(1), 16 U.S.C. § 839b(e)(1) (Supp. V 1981).

90. *See supra* note 43 (discussion of System Analysis Model).

91. Note that the record of forecasting provides only limited support for the hypothesis that uncertainty decreases as one approaches the point of actual use. *See supra* note 31 (discussing track record of PNUCC forecasts).

92. *See* Lee, *supra* note 24.

93. *See* BPA 1982 FORECAST, *supra* note 9, at 21–22.

trend is nearly certain to lie? How much and little can electric energy users respond to changes in rates? Additional information comes from analyses of the relative costs of over- and under-building. A power shortfall of, say, 3000 megawatts does not have the same impact as a 3000-megawatt surplus.[94] One could choose bounding forecasts so that the upper and lower bounds reflect *equivalent* costs to the regional economy.[95] More generally, using economic forecasting to set limits for planning is a more modest task than identifying a precise target. There is reason to hope that approaches such as those sketched here would lead to estimates that are more scientifically sound and less burdened by political ideology.[96]

In sum, the schematic risk management approach illustrated here replaces the concept of a single best forecast with an iterative three step process:[97]

> *1.* Use the best forecasting data and methods available to project the highest and lowest plausible cases. These *upper and lower bound forecasts* should reflect a range of demand broad enough that the actual demand can be confidently assumed to fall between the bounds.
> *2.* Develop a stack of resource possibilities to fill the span between the lower and upper bounds for each year in the plan. The region should retain the right to delay acquisition in light of additional information about expected costs and demand. Options to sell part of the output of large facilities, together with purchase options—regional financing of project initiation costs—can facilitate the development of resource possibilities while retaining flexibility.
> *3.* Make decisions as necessary on resource possibilities, so that there will be *resources acquired to meet the lower bound forecast*, and so that there will be a *combination of resources and options* capable of covering demand

94. Under existing rate structures (for surplus) and curtailment rules (for shortage) imbalances between supply and demand are not allocated to minimize economic impact. *See* WSEO II, *supra* note 1, at 13–14; ICF, INC., RESERVE-RELIABILITY ANALYSIS, STUDY MODULE V ch. 3 (Aug. 1982) (final report to the Northwest Power Planning Council).

95. ICF, Inc., has performed an analysis of how shortages could be allocated to minimize economic impact. *Id.* ch. 4. Were such an approach politically feasible, this analysis could be supplemented by a study of how the burden of a surplus could be similarly allocated.

96. *See, e.g.*, ELECTRIC POWER, *supra* note 5, at 136 figure 16 (illustrating that power demand projections correlate strikingly with ideology).

97. The Council's planning philosophy contemplates a more detailed seven-step analysis: (1) Develop a range of forecasts. (2) Develop alternative resource portfolios. (3) Using the PNUCC Systems Analysis Model (*see supra* note 44) and other simulation techniques, assess the probable performance of alternative portfolios. (4) Assess the implications of the uncertainty in load forecasts in each of the alternative portfolios. (5) Revise portfolios in light of insights developed by earlier steps. (6) Evaluate alternative portfolios, incorporating judgmental factors such as the tradeoff between cost and lead-time. (7) Examine the effect of the selected portfolio on rates, and thereby reconsider the range of forecasts used to initiate the analysis. Options Memorandum, *supra* note 51, at 5–11.

ranging *as high as the upper bound forecast* in *each* target year. Acquisitions should be made following the cost-effectiveness and resource priorities set forth in the Northwest Power Act.

Regional risk management brings to the fore the question of whether it is possible to put a great deal more flexibility into the acquisition process. Before discussing some of the practical issues raised by the idea of options, one should pause to observe that *flexibility may not be desirable in all cases,* nor may it be obtainable on favorable terms. First, electric power planning does not take place in a vacuum; there are costs and benefits to others, and these costs and benefits depend upon how utility resources are scheduled. For example, Northwest electroprocess industries invest large sums in capital equipment on the assumption that power will be available to utilize it. The Northwest Power Act recognizes the value of secure supply to the direct-service industrial customers.[98] More generally, flexible, risk-oriented planning benefits some and imposes risks and costs on others but our understanding of the distributive effects of a new planning method is necessarily limited.[99]

Second, a flexible, incremental approach encounters the problem of "second best."[100] Incremental decisions, each of which is rational, may lead to a suboptimal outcome. Second best is the economists' version of the road paved with good intentions. For instance, vigorous attempts to improve the accuracy of forecasts—a rational program—may lead planners to have an inappropriate confidence in their estimates of future demand; thus, incremental improvements in the single best forecast do not lead one to the rather different approach suggested here. It is important to bear in mind, then, that flexibility is desirable as a means to a larger end: cost-effective power supply. On account of both the external effects of planning and the problem of second best, it is wise to be cautious about the value of flexibility. But a flexible approach has obvious merit in the uncertain environment faced by the Northwest.

IV. PRACTICAL QUESTIONS

Regional risk management is clearer conceptually than practically. The ideas discussed in this article are familiar and well-established in business, especially in finance and other cyclical industries. Yet applying

98. *See* Northwest Power Act, *supra* note 2, § 5(g)(1)(D), 16 U.S.C. § 839c(g)(1)(D) (Supp. V 1981); H.R. REP. No. 976, 96th Cong., 2d Sess., 28–29 (1980), *reprinted in* LEGISLATIVE HISTORY, *supra* note 3, at 333.

99. WSEO II, *supra* note 1, at 14.

100. *See* Lipsey & Lancaster, *The General Theory of Second Best*, 24 REV. ECON. STUD. 11 (1958).

them to the complex web of technological and institutional relationships that constitute electric power in the Northwest will be challenging. The promise of the risk-management approach is large: it is the one conceptual framework that offers significant, achievable strengths in facing uncertainty.

The region will be served best by a vigorous critique of the risk-management concept. What are the barriers that stand in the way of using these ideas to structure the regional plan? What special advantages might accrue from using a risk-management approach, and what special disadvantages are attached to using it? Who will benefit, and who will lose, if a risk-management philosophy is adopted? Most of all, is flexible planning practical given the regional power system as it is, and will a system shaped by regional risk management be a better one for the ratepayers of the Northwest?

The key questions are those that surround measures to increase planning flexibility, especially resource options:

1. Who will find it sensible to provide options, and under what conditions?[101] What are the legal, economic, institutional, or psychological barriers that inhibit the development of options?
2. Are options compatible with the Northwest Power Act? Is the language of section 6(f),[102] providing for reimbursement of resource development expenses,[103] adequate as a legal framework for using options?[104]
3. Are options compatible with regulatory rules?[105] Approval for major generating facilities usually requires determination of the need for power[106]—a

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101. It is noteworthy that the PNUCC urges utilities to "participate with BPA in contract development for optioning resources." PNUCC Options Paper, *supra* note 7, at 9.

102. Northwest Power Act, *supra* note 2, § 6(f), 16 U.S.C. § 839d(f) (Supp. V 1981).

103. *See* PNUCC Options Paper, *supra* note 7, at 30–31.

104. Using the billing credits provisions of the Northwest Power Act, *supra* note 2, § 6(h), 16 U.S.C.§ 839d(h) (Supp. V 1981), may provide a means for reimbursing utilities for options as well. PNUCC Options Paper, *supra* note 7, at 11.

105. *See* BATTELLE OPTIONS STUDY, *supra* note 51, § 4.0 (discussing legal and institutional complexities in developing options). The Council has concluded that:

> it is unlikely that all of the regulatory, legal, and institutional difficulties with the option concept can be resolved [before the first regional energy plan is completed in April 1983]. The Council's Plan will provide incentives to assist option developers to bring the concept of options to the point where the region can purchase an options portfolio. These incentives will include preconstruction financing, power marketing assistance, long-term power sales contract[s], and assistance from the Council in regulatory proce[e]dings and regulatory reform. It is important that the Council's plan commit to working with the region's utilities and resource developers to fully operationalize the options concept.

Options Memorandum, *supra* note 51, at 4.

106. *See* IDAHO CODE § 61-528 (1976); MONT. CODE ANN. § 75-20 (1981); OR. REV. STAT § 469.300 (1981); WYO. STAT.§ 37-2-205. *See also* PNUCC Options Paper, *supra* note 7, at 13–14. Of course, the need for power test applies only to the large facilities specified in these laws. Conservation, some renewable resource projects, and some high-efficiency resources like fuel cells therefore do not face this regulatory complication.

determination that is eschewed in flexible planning. "Banking" a site entails a commitment by regulatory agencies that *future* regulations will still be consistent with use of that location.[107] Permits and licenses for projects often carry deadlines, limiting the allowable delay between licensing and the start of construction;[108] changing this aspect of the rules of many agencies will not be easy. State and federal regulations pose a significant barrier to regional risk management.

4. Presumably, the front-end costs of most power supply projects are small near the time of initiation: design, siting, and licensing are all activities that require far less expenditure than construction. So an option could be purchased at modest cost. But are conservation programs like this? What about experimental resources that may involve substantial research and development costs? More generally, what determines the cost of an option in a technical sense?[109]

5. Why would a project sponsor be willing to delay or halt a project once it is begun, and do so on the basis of *regional* criteria interpreted by the Council or BPA?[110] In part, this is a matter of what the region is willing to pay for the option in the first place. More generally, what negotiating factors influence the price of an option?[111]

6. How reliable are the cost and schedule estimates of options? Can they be made at least as credible as those for projects proposed for acquisition or billing credits under the Act? An especially important question is *schedule slippage.* It may be crucial to provide assurance that designation as an option will not increase the probability that a project will be slowed by anyone besides BPA and the Council.[112] Schedule slippages in the years preceding passage of the Act may have sustained the tendency to overbuild resources over the past decade. Overcoming the utilities' fears of slippage is a major hurdle for any planning process, perhaps especially so for one incorporating projects subject to regional review after they are underway.

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107. *See id.* at 14. For example, the requirements of the Clean Air Act, Pub. L. No. 91-604, 84 Stat. 1676 (1970) (codified as amended in scattered sections of 42 U.S.C.), include re-evaluation of the "best available control technology" for projects that are delayed. 40 C.F.R. § 52.21(j)(4) (1981).

108. A hydroelectric project licensed by the Federal Energy Regulatory Commission (FERC) is bound by provisions of § 13 of the Federal Power Act, 41 Stat. 1071 (1920) (codified as amended at 16 U.S.C. § 806 (1976)); construction must begin within two years, unless FERC grants a two-year extension. Even small hydro projects (generally, under five megawatts of electric capacity), which are exempted from FERC regulation, must begin construction 18 months from the time an exemption is granted. 18 C.F.R. § 4.106(c) (1981). *See* PNUCC Options Paper, *supra* note 7, at 14–15, 42–46.

109. *See* BATTELLE OPTIONS STUDY, *supra* note 51, § 6.0 (discussing costs of acquisition of electric power conservation and supply resources); WSEO I, *supra* note 1, at 8–11.

110. *See* PNUCC Options Paper, *supra* note 7, at 48 (discussing the value of an option to its sponsor).

111. The price allowable under federal statute may be uncertain. *Id.* at 47. The negotiating stance of BPA is also affected by considerations of how purchase of options will affect the stability of and increases in consumer rates. *Id.* at 31–34.

112. The PNUCC notes the importance of according optioned projects the same priority in processing regulatory clearances as for projects that are acquired. PNUCC Options Paper, *supra* note 7, at 15.

7. Some options involve few direct costs beyond those of negotiation, such as contractual arrangements for power sales or purchases. What options for the Northwest are to be found in the plans of utilities in neighboring regions such as California or western Canada? Note that this question is similar to that of load diversity, but the focus is on planning rather than operations.
8. Are there institutional arrangements other than contracts that can facilitate options? Are there conditions in which having shared ownership is advantageous? The aluminum industry has played an important role in the Northwest power system by providing a market for reserves that had no alternative market;[113] are there similar industry-utility compatibilities with respect to resource options?
9. If options are obtainable, which characteristics are most valuable? What is the relative value, for instance, of cost as compared to lead-time? Of size compared to the uncertainties of completion on time? Does putting a high value on flexibility lead to unanticipated results?[114] This article has implicitly assumed that cost and flexibility were the only relevant variables, but clearly that is not so. What would one want from an option? What makes an option a valuable form of insurance to the region?[115]
10. What sort of options might be helpful if the lower bound forecast indicates prolonged periods of power supply surplus or even declining demand in the region?[116]
11. This article has implicitly assumed that central planning for the whole region will prevail. But large utilities will continue to operate autonomously within the Bonneville service area. How are they affected by a shift to a flexible planning process? Neither their technological or economic ability

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113. *See* Redman, *supra* note 79.

114. For instance, flexibility can be enhanced by choosing technologies that have low capital costs and high running costs. That way, a project that is little used does not exact a high penalty. So risk management may be an unrecognized argument for burning oil in combustion turbines, a resource possibility that conflicts with the national goal of limiting dependence on imported petroleum. Powerplant and Industrial Fuel Use Act of 1978, Pub. L. No. 95-620, 92 Stat. 3289 (codified at scattered sections of 15, 19, 42, 45 & 49 U.S.C. (1976)). For a general discussion see Herzog, *The Coverage of the Fuel Use Act: How to Avoid Unpleasant Surprises,* 13 NAT RES. L. 553 (1981).

115. The insurance value of an option should decrease as the cost of power from that option increases. A low-cost option is likely to be developed anyway, and thus the ability to delay or terminate it is less valuable than for an option that would produce power at higher cost. The cost of an option may rise, however, for projects deferred into the future. PNUCC Options Paper, *supra* note 7, at 11.

The PNUCC also observes that the value of an option to the region must also be weighed against the budgetary and financial constraints facing the Bonneville Power Administration. *Id.* at 28–30.

116. The Northwest Power Act was written in the face of fears of imminent power supply shortages during the 1980's. S. REP. No. 272, 96th Cong., 1st Sess. 17 (1979), *reprinted in* LEGISLATIVE HISTORY, *supra* note 3, at 445. The publication of the WERC FINAL REPORT, *supra* note 11, and the BPA 1982 FORECAST, *supra* note 9, has led to a substantial revision of expectations in the region and among investors in the national capital markets. The prospect of a period of electricity surplus has also affected the outlook for the Council's regional energy plan, in that utilities are no longer under immediate pressure to propose projects for the plan.

nor their continuing willingness to participate in a centrally-directed risk management strategy can be assumed.[117]

12. Can the fragile and complicated regional utility industry structure absorb the complexities of flexible planning? If the region's utilities were a single organization, this would be a question of corporate strategy. Within the existing fragmented situation, there is a danger that this system-level institutional question will not be considered seriously enough.[118]

V. CONCLUSION

The risks that face the Northwest are plainly visible. The technical and institutional means of taking account of these risks in regional planning are now being developed. Individual utilities have, of course, invented sophisticated means to insulate themselves from the effects of the kind of uncertainties analyzed here. Moreover, through instrumentalities such as the Pacific Northwest Coordination Agreement of 1964 or the Northwest Power Pool founded in 1942, the utilities have acted at the regional level to address *technological* uncertainties.[119] The conditions that confront the region today arise primarily from social and economic rather then technological uncertainties; and the principal instrument for coping with these uncertainties is the new institutional framework created in the Northwest Power Act.

Because of the limited authority granted BPA and the Council in the Act, the methods of recognizing, analyzing, and adapting to changing conditions at the regional level are critically dependent upon informed,

117. The possibilities of rapid change are illustrated by the residential power-exchange authorized in the Northwest Power Act, *supra* note 2, § 5(c)(1), 16 U.S.C. § 839c(c)(1) (Supp. V 1981). Perhaps the most powerful impetus to passage of the Northwest Power Act was the perception that large rate disparities between the wholesale power costs of publicly and privately owned utilities had to be ameliorated in substantial degree. (The disparities arose from the preference and priority provisions of the Bonneville Project Act, 16 U.S.C. §§ 832d & 832f (1976 & Supp. V 1981) . This is accomplished in the Act by providing for an exchange of power between a utility and BPA; in this exchange, the utility surrenders power at its average cost of generation ("average system cost," defined in section 5(b)(7) of the Northwest Power Act, 16 U.S.C. § 839c(b)(7) (Supp. V 1981) and receives power at the Bonneville Administrator's cost. The quantity of power eligible for the exchange is limited to that sold to residential customers, under § 5(c)(1) of the Act, 16 U.S.C. § 839c(c)(1) (Supp. V 1981). This exchange provision was written under the assumption that BPA wholesale costs would continue to be lower than those experienced by investor-owned utilities. That has not turned out to be the case, however, and several utilities have now discontinued their exchanges with BPA. Similarly, I have assumed in this article that an option developed within the risk-management framework will continue to be desirable to all affected parties, including the project sponsor, BPA, and the Council. Rapidly changing relative costs and shifts in demand forecasts—both common during recent years—could readily invalidate this assumption.

118. *See* ELECTRIC POWER, *supra* note 5, ch. 3, for a parallel analysis of the Hydro-Thermal Power Program, which faltered, in part, because it sought region-scale objectives without adequate commonality of interest among its autonomous participant utilities.

119. *Id.* ch. 2–3.

creative, timely, and constructive leadership from the utilities, state and local governments, and interest groups. The concepts of flexible risk management set forth here are offered as a framework within which genuinely collaborative planning can take place.