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Aligning a Utility's Interests with the Public Interest in Cost-Effective Purchased Power Transactions

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Executive Summary

This report examines regulatory tools with the potential of aligning the utility's private, profit-maximizing interest with the public interest regarding the cost-effective use of long-term purchased power as part of a utility's least-cost resource plan. The paper discusses the current misalignment of private with public interests and the challenge to achieve alignment. After discussing how to evaluate these tools, the paper examines five potential tools: (1) compensating a utility for the cost effectiveness of its purchased power program through an adjustment to the authorized rate of return; (2) including purchased power in the utility's rate base; (3) recovering purchased power costs through base rates rather than through an energy cost adjustment mechanism; (4) price cap regulation; and (5) sharing the savings produced by cost-effective power purchases.

Regulators might choose to use some of these tools in combination (e.g., shared savings with base rate or energy price adjustment cost recovery). Others cannot be combined (e.g., rate-of-return adjustments and price cap adjustments are mutually inconsistent). The current paradigm does not create confidence in utilities making sound public interest decisions, as they may compensate a utility more for making decisions that do not result in cost effectiveness.

This paper suggests that regulators may be able to further the public interest by compensating utilities for cost-effective least-cost planning actions that involve long-term purchased power transactions in ways that are practical and transparent. The table on the last page of the report summarizes the author's judgments of the efficacy of the respective tools.

A symmetrical shared savings approach that compares a utility's power purchase proposals to a proxy plant has promise. Avoiding the misalignments associated with traditional energy clauses by applying base rate purchased power recovery or an energy price adjustment clause also has merit, subject to the availability of production cost modeling resources.

The other approaches discussed in this paper seem to have less merit. Rate-of-return increases for cost-effective purchased power transactions lack precision while potentially increasing the misalignment of interests by increasing the compensation a utility receives for resources it builds.

Inclusion of capacity costs of a purchased power transaction in rate base aligns the compensation a utility receives for building or buying resources but does not align the utility's interest with least-cost resource planning.

Price caps, although normally applied to transmission and distribution services, could help align public and private interests for purchased power if applied to energy costs. A more targeted solution, however, may be the energy price adjustment tool, which works similarly to price caps for energy costs without requiring that the regulator shift its entire ratemaking paradigm from a cost-of-service approach.

As with any regulatory tool, the devil is in the details. All of the discussed approaches require additional refinement, based upon factors such as local law and regulations, market conditions, the availability of information, and the regulator's resources.

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I. Aligning interests regarding long-term purchased power resources

A. Regulatory structures need to align a utility's interest in resource planning with the public interest

A fundamental purpose of utility regulation is to align the utility's private interest with the public interest. Regulators must ensure that each utility uses the proper mix of resources—those it builds and those it buys from others—and that these resources are cost-effective components of a least-cost resource plan.

The quest to align the private with the public interest has arisen in discussions of a utility's propensity to "gold-plate" its capital investments; to build excessive capacity; to ignore development of demand-side resources that reduce revenues; to give short shrift to integrated resource planning; and, as discussed here, to shun resources acquired externally through competitive bidding or otherwise. This paper discusses potential tools that regulators may wish to examine as means to align the utility's private interest with the public interest with respect to long-term power purchases.

Economic theory, starting with Adam Smith and his "invisible hand," instructs that individual consumers and businesses in a competitive market, acting in their own best interest, should produce an efficient cost-minimizing and benefit-maximizing solution for the economy as a whole. Because utilities are monopolies, regulation needs to adopt other tools to complement or replace rate base, rate-of-return regulation to compensate utilities for cost minimization. Utilities are required to provide service to their customers at a just and reasonable cost, subject to applicable constraints such as reliability and environmental rules. Some regulatory structures, however, compensate a utility more richly for decisions that do not achieve a least-cost goal. For example, some regulatory structures pass changes in a utility's power plant productivity through to customers, but make the expense associated with power plant efficiency the responsibility of the utility. Although the utility has a responsibility to minimize costs, the regulatory structure may compensate the utility more richly when it does not cost minimize.

B. Misalignments of interests regarding building or buying resources

Regulators want to make sure that utilities provide adequate and reliable electricity service at the lowest reasonable cost. Utility management generally embraces the duty to provide capacity and energy; however, whether the approaches taken by utilities are least-cost has been the subject of debate. This paper focuses on the financial challenges of aligning a

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[1] The views expressed in this document are those of the author and not of NRRI or its dues payers.

utility's interest with the public interest. Under rate base, rate-of-return regulation, a utility will often prefer to build rather than buy new power resources, even when purchased resources may be more cost-effective. The seminal piece of economic literature on this topic found that traditional rate base, rate-of-return regulation encourages utilities to substitute suboptimal capital investment for non-capital production factors, since utilities have an opportunity to earn a return only on capital, but not on costs that are not included in the rate base.[2] Economists call this misalignment of the utility's private interest and the public interest the Averch-Johnson effect. Economic literature also poses an anti-Averch-Johnson effect, under which a utility shies away from certain capital investments when it views the risk of a construction project as exceeding its potential return.[3] In that case, utilities may pursue power purchase options that are not cost-effective. Regulators should be concerned about regulatory structures that unduly compensate a utility for foregoing cost-effective resource decisions, whether they involve building power plants or purchasing power.

An issue pertaining to the alignment of interests regarding purchased power is whether it is appropriate to add a utility profit on top of a profit to the wholesaler. Except in the case of affiliated interest transactions (see Sec. II.C.2, below), regulators should not worry about compensating utilities for cost-effective purchased power transactions in addition to profits to suppliers. Regulators routinely allow the inclusion of profits earned by input or component suppliers to utility-built resources. Sometimes a utility may acquire a resource through turnkey agreements, in which a third party builds and operates a plant that the utility owns. In that case, the developer earns a profit separate from the utility's authorized rate of return. The appropriate focus should be on compensating utilities for superior decisions, not on whether the utility or another party owns or operates the resource, or whether others earn a profit.

C. Purchased power: the alignment challenge

Regulators must address two separate but related issues when seeking to align the private with the public interest: (1) whether the regulatory structure compensates the utility appropriately for buying power as compared to building a resource, given the difference in risk, and (2) whether the regulatory structure compensates a utility for minimizing its purchased power costs.

Development of appropriate regulatory tools should align the private interest with the public interest such that the regulator does not need to insert itself unduly into decisions that a utility makes. Regulators should enable and compensate utilities for effective management without becoming excessively involved in management's core responsibilities.

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[2] Harvey Averch and Leland L. Johnson, *Behavior of the Firm under Regulatory Constraint*, ECON. REV., vol. 52, no. 5, Dec. 1962.

[3] William J. Baumol & Alvin K. Klevorick, *Input Choices and Rate-of-Return Regulation: An Overview of the Discussion*, (1970) BELL J. OF ECON. MGT. SCI. vol. 1, no. 2, Autumn 1970.

D. Assumptions, caveats, and paper structure

For the purposes of this paper, the author assumes that utilities may either build or buy resources to meet their incremental needs. Its focus is on long-term purchased power agreements comparable to utility-built plants, not short-term purchases. The paper also assumes that the utility's integrated resource plan has identified a need to acquire base-load supply (whether to be built by the utility or purchased), and that any power purchases are from independent third parties and not entities affiliated with the buyer.

This paper focuses on potential regulatory tools that might provide a utility appropriate compensation for cost-effective purchased power resources.[4] This paper does not look at regulatory tools that seek to align the utility's *behavior* regarding purchased power, focusing rather on aligning the utility's *interest* with the public interest.[5] The next sections of this paper discuss guidelines for evaluating these tools, as well as factors that can influence the evaluation.

II. Evaluating regulatory tools regarding long-term purchased power

A. Does the regulatory approach align the interest of the utility with least-cost resource acquisition?

Utilities are required to provide service at just and reasonable rates. Superior regulatory tools will align a utility's interest to profit with the public interest to minimize costs.

B. Is the proposed regulatory approach efficient to implement and transparent?

A regulatory tool should be practical, reliable, and understandable. If information needed to implement a particular tool is not available (e.g., if no reasonable benchmark exists for a shared savings calculation), the tool is not practical. If the tool causes uncertainty or contention as to the proper compensation for a utility's behavior, the tool is not transparent. The more predictable the outcome of a well-aligned tool, the better, recognizing that regulatory judgment may still be required with certain tools (e.g., rate of return).

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[4] This paper does not purport to be a complete examination of all the options. The author is an economist and not a lawyer, so this analysis will not consider specific laws, regulations, or legal precedent. Facts and legal structures vary from case to case and state to state. This paper does not suppose that one solution is universally applicable, nor does it determine the appropriateness of any particular regulatory treatment, purchase, or project; neither does it attempt to compare the cost-effectiveness of various resources.

[5] For historical overviews on the increased role of purchased power and discussions about regulatory efforts to address the issue of cost-effective purchased power transactions through procedural or behavioral approaches *see* Susan F. Tierney and Todd Schatzki, *Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices*, Analysis Group (July 2008); Gregory Basheda and Adam Schumacher, *Buy versus Build: A Survey of State Policies*, ELEC. J., Nov. 2008.

Different regulatory tools require different degrees of regulatory involvement. A critical question is whether the regulator has the capacity to identify and act upon those cases where a utility is not performing in the public interest. Some regulatory tools require more resources to administer than others (e.g., they may require excessive hearings, audits, or hiring of consultants). The transparency of the compensation paradigm will affect the degree of oversight required. Not all regulators have the same level of resources, so a method that may be a good fit in one jurisdiction may not be appropriate elsewhere.

C. Influencing factors

The evaluation of regulatory tools does not occur in a vacuum. Whether a utility should build a plant or purchase power, and whether a change in a utility's compensation is necessary to align the utility's private interest with the public interest, depends on factors such as the ones noted below.

1. Risk and purchased power

Both utility-constructed power plants and long-term purchased power commitments involve degrees of risk. The risks of a purchased power transaction will depend on the terms of the agreement and will affect how the utility and regulator view the value of the transaction. This section includes a discussion of some of these factors.

a. Prudence review

The process by which a regulator determines the prudence of utility resource decisions goes to the heart of the goal of aligning private and public interests. Traditionally, regulators did not rule on the prudence of utility plant construction or long-term power purchases until a utility finished construction and proposed it to the regulator as an addition to rate base or purchases were made. Over the past several decades, utilities have asked regulators to provide prior approvals of the prudence of construction projects and long-term contracts**.** For utility-built resources, utilities often seek this approval many years prior to the resource being determined "used and useful," and available for service. For long-term purchased power contracts, utilities seek a prudence review relatively contemporaneously with availability of the resource, assuming the facilities for the purchase are in operation. If the power purchase is for a project not yet completed, utilities may seek prior approval of the purchase agreement as they would for a utility-built plant. Any preapproval by a regulator needs to produce a benefit to the utility's customers, not just shift risk from the utility to its customers. The process must be timely and allow for the full review of relevant facts. Regulators must focus and condition any preapprovals granted. The regulatory body must possess the financial and staff resources to permit timely and thorough review.[6]

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[6] For a more detailed discussion of pre-approval, *see* Scott Hempling and Scott H. Strauss, *Pre-Approval Commitments: When and Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?*, NRRI, Nov. 2008.

b. Imputed debt and financial risks of plant construction

The current literature on purchased power is replete with discussions about imputed debt. Rating agencies impute debt on certain purchased power contracts, as the utility's obligation to pay appears similar to a balance sheet obligation to pay debt. Some critics of this concept claim that if the recovery of the cost of purchased power is relatively assured by a specific regulatory finding (e.g., of prudence, or through energy cost true-up mechanisms) or by practice (no history of denying purchased power costs), then the obligation to pay under the contract should be offset by revenues and should not be treated as the equivalent of debt. Regulators should include the cost of imputed debt in resource evaluation only if the cost is demonstrated to be real and reasonable or, in the case of a forecast, a reasonable estimated of an expected cost.

There are also financial risks associated with building a plant, even when the regulator declares a project prudent prior to construction. The regulator may find later that the utility has not constructed or operated the plant prudently. Raising large amounts of capital can cause devaluation of a utility's stock price, create pressure to increase the authorized return on equity, and negatively affect a utility's bond rating. These secondary costs of utility power plant construction should be included in a resource evaluation calculation when they can be demonstrated, just as imputed debt may be included in the cost of some purchased power options.

c. Purchased power versus build operations risks

Purchased power contracts are in several ways less risky financially to a utility than building generating plants. The utility can make a buy decision later than it makes a build decision, assuming that there will be resources to buy—a potential risk of not building. A deferred decision allows a utility to have a better idea of its demand when committing to new supply. In a build-and-operate situation, utilities bear the risks of construction delays and overruns, operations, and environmental compliance. Purchased power agreements typically shift these risks to the supplier. The risks of fuel price changes are usually relatively the same between buy and build options, unless the sources of generation are different (e.g., wind vs. fossil fuel). Purchased power agreements either contain fuel price adjustments or require the utility to deliver fuel to the supplier (under tolling contracts). Regulators usually afford utility-built resources fuel price adjustments.

2. Affiliated interest purchases

A utility might wish to purchase power from an independent third party, as assumed in this paper, or from a corporate affiliate. Affiliates include other utilities or non-regulated entities owned by the utility or within its parent company structure. Any transaction a utility enters into with an affiliate should be subject to rigorous regulatory oversight. A thoughtful competitive procurement process can assure fair treatment, as between an affiliate and other potential suppliers. Unlike cases in which the utility is purchasing power from an independent, non-affiliated seller, when the utility purchases from an affiliate, its own corporate entity will profit from the transaction, so additional compensation to the utility buyer may not be appropriate.

III. Potential regulatory tools to align the private interest with the public interest

This section discusses five regulatory tools that regulators could consider to align private with public interests regarding utility long-term purchase power agreements.

A. Rate-of-return adjustments

Regulators have discretion to determine what rate of return to authorize when establishing a utility's revenue requirement and base rates. Many factors may influence this decision. Often, adjustments are subjective and not explicitly stated by the regulator in its rate case decision.

Regulators, concerned about the lack of use of purchased power in their utilities' least-cost resource plans, could explicitly state that improvement in this area will be a consideration when the commission next authorizes a rate of return for the utility. Is this regulatory tool a reasonable way of aligning the private interest with the public interest regarding the cost-effective use of purchased power?

Any tool that compensates a utility for cost-effectiveness moves towards aligning the private with the public interest. This particular tool, however, may be too subjective. How much of an adjustment? How should a regulator determine cost effectiveness? What if a rate of return adjustment for this purpose cannot be made within a reasonable range? Will utilities be concerned that their long-term purchased power will reduce their authorized rate of return because of the shift in risk from the utility to the supplier? Given a commission's overall discretion regarding rate of return, can a utility rely upon an explicit adjustment for purchased power cost effectiveness not being offset by some other subjective adjustment?

Regulators should always look at the utility's cost effectiveness in setting a rate of return, but this seemingly simple focus on purchased power may not provide sufficient clarity to the utility or the regulator to align the private interest with the public interest. The adjustment is easy to implement, but the range of judgment vested in the regulator makes the approach less than transparent. For this tool to be of value, regulators would need to state a policy indicating the degree to which this factor would be considered in setting the rate of return and how the cost effectiveness of purchased power is determined. Even this effort to introduce precision may not be sufficient to bring transparency to this tool, as the explicit adjustment regarding purchased power may become "noise" in the regulator's final rate-of-return determination. Also, increases in the allowed return for any reason may cause utilities to favor self-built resources as discussed at section I.B, thereby causing an offsetting misalignment with the public interest.

B. Purchased power capitalized in rate base

Regulators sometimes permit utilities to capitalize certain expenses and amortize the capitalized expense over multiple years, with the unamortized amount earning a return in rate base. Could this type of regulatory approach align the private interest with the public interest for utility purchased power practices? Regulators typically use expense capitalization to allow utilities to recover non-recurring costs such as storm damage or to reserve funds for a future expense. Capitalizing a current or recurring purchased power expense is different from the typical application. Some have suggested that the capitalization of purchased power would require that the utility pay for the long-term contract at the outset, on a net-present-value basis—i.e., to capitalize the stream of costs. This up-front payment would shift risks from the supplier to the utility and its consumers.

What are the non-legal issues[7] of capitalizing purchased power expenses as a way of aligning the private with the public interest?

First, what costs should the regulator capitalize? Should the total net present value of the project be capitalized, or only the capacity portions? Energy costs may not even be known at the time the purchased power contract would be capitalized, or could change over the contract term.[8] If only capacity costs of purchased power are included in rate base, however, utilities and suppliers could write contracts that shift costs from energy to capacity in a way that shifts risks to customers. If capacity receives more favorable regulatory treatment than energy, utilities may focus on using more capital-intensive technologies (e.g., wind or nuclear rather than coal or natural gas) rather than less capital-intensive resources (e.g., gas-fired generation) that may or may not be less costly.

Second, what would be the mechanics for capitalizing or creating the net present value of the purchase? The regulator must determine appropriate discount rates, an issue that can shift the costs and risks of the project between investors and consumers.

Third, what is the appropriate rate of return? As discussed at II.B.1.c, purchased power contracts normally shift risks to the supplier that would rest with the utility under build scenarios. Awarding the same return for lesser risk fails to align private interests with the public interest. Should (and may) regulators create a separate purchased power rate base? Should the regulator reduce the overall authorized return and apply it to the larger rate base?

This tool has the theoretical potential to align build and buy resources, with regulators allowing returns on either type of resource. But it is an awkward tool that may improperly compensate the utility for spending more for power purchases rather than for minimizing costs.

Mississippi passed a law in 1994 that permits the utility to earn a return on capacity purchases subject to regulator review and approval.[9] Discussions with Mississippi Commission staff indicate that there are no such current purchases. Utilities in Hawaii recently proposed[10] to include ten percent of the costs associated with purchases required through feed-in tariffs for

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[7] Legal questions associated with this approach are beyond the scope of this paper.

[8] In the build scenario, the regulator does not include the price of fuel in the utility's rate base.

[9] Miss. Code Ann., sec. 77-3-95

[10] Docket No. 2008-0273, Hawaii Public Utilities Commission: Joint Proposal on Feed-in Tariffs of the HECO Companies and the Consumer Advocate, Dec. 23, 2008.

renewable resources in rate base. The utility suggests this rate base inclusion as a possible way of redressing a potential imputed debt issue. The Hawaii Commission had not ruled on this matter as of this writing.

C. Base rate cost recovery or energy price adjustment mechanism

There are three basic mechanisms for purchased power cost recovery:

1. Through an energy cost or purchased power rider that passes through costs to customers without regard to productivity.

2. Through base rates. Base rates are the rates set by a commission in a rate case. Base rates are different from riders that allow for inter-rate case adjustments, such as fuel adjustment clauses**.**

3. Through an energy adjustment clause or purchased power rider, which focuses on changes in price that are outside of the utility's control, rather than changes in productivity.

Each of these approaches bears on how purchased power contract terms such as dispatchability and availability affect a utility. Long-term purchased power resources are part of a utility's resource portfolio, contributing to its overall cost effectiveness. The terms of the purchased power agreement will affect whether the utility dispatches the resource like a must-run unit, which may on occasion displace cheaper available resources, or more like a dispatchable unit that can have its marginal output increased or decreased to respond to changes in load, prices, and availability of other units. Other terms of a purchased power contract determine the supplier's responsibilities (e.g., payments for replacement power when the supplier does not deliver contracted power).

Method 1 from the list above creates the greatest misalignment of the public and private interests, as it completely shields utility earnings from any change in price or output of the purchased power. The utility is indifferent, from a financial perspective, as to whether the purchased power displaces more cost-effective resources and is available at times of critical need, unless other portions of the regulatory paradigm make the utility responsible for cost changes tied to the rest of its resource portfolio.

Method 2 calls for recovery of purchased power costs through base rates and places all the responsibility for changes in purchased power costs from those included in base rates on the utility. If the utility recovers all of its supply costs through base rates, increases in the availability of cost-effective purchased power will offset the need to use resources that are more expensive and have a positive effect on utility earnings. The contractual terms regarding availability, controllability, and price changes all affect the utility bottom line consistent with cost minimization goals. Base rate cost recovery of purchased power and other supply resources aligns the private and public interests; however, it also makes the utility responsible for changes in fuel prices that may be unpredictable and beyond the utility's control.

Method 3 proposes the use of an energy price adjustment rate clause (EPAC) rather than a cost rider. It differs from Method 1 in that Method 3 only makes adjustments for changes in price and not power plant productivity (e.g., heat rate or availability) or purchased power availability. An EPAC is only one of many productivity adjustments to a full pass-through mechanism that can improve the alignment of the utility's interest to the public interest. The alignment of the public and private interest in Method 3 and Method 1 is similar, except that in Method 3 the utility recovers often-unpredictable changes in fuel prices from customers.

Under an EPAC, when a purchased power contract requires power delivery that best fits the utility's total resource needs, the utility improves the potential for that transaction to improve the cost effectiveness of its energy portfolio and simultaneously improves its opportunity to improve its profitability. Utilities can profit from managing factors within their control and are able to pass on to customers changes in fuel prices that may be exogenously determined. This alignment of the private with public interest links the utility's profitability to the underlying terms and conditions of its purchased power contract. It reduces the need for regulators to examine every aspect of a purchased power contract, as the regulator has taken steps to ensure that cost effectiveness is in the utility's own interest. The regulator still needs to review any price indexes or inflators included in the contract, as they would be the responsibility of customers. Fuel-price-related issues such as fuel price hedges and tolling agreements (purchased power transactions where the utility provides the fuel to the seller) still require fuel acquisition oversight by the regulator.

There are numerous benchmarks that the regulator must set, implicitly or explicitly, when including purchased power in base rates or recovering purchased power costs through an EPAC; these include factors for production cost models such as load shape, demand-side response capabilities, heat rate, and availability. When using base rate or EPAC cost recovery, the regulator must be comfortable with the workings of the utility's production cost model (or its own or independent models), and must have the resources and information to determine reasonably these model input factors.

D. Price cap regulation

Price cap regulation is a regulatory paradigm that focuses on price, rather than costs as in the traditional cost of service model. In a price cap approach, there is no rate base or rate of return. (See the note below for a mathematical comparison of the price cap and cost-of-service models.[11])

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[11] Paul Joskow, *Incentive Regulation in Theory and Practice: Electricity Distribution and Transmission Networks,* Jan. 21, 2006 (rev'd) compares a cost of service approach to a price cap in mathematical terms.

$R = a + (1-b)*C$, where R = allowed revenues, a = fixed component, C = the utility's realized costs, and b = a sharing parameter that defines how closely costs and revenues are linked.

The elimination of rate base removes the Averch-Johnson misalignments discussed above. The regulator sets a price, based on (but not confined by) cost information. That price then serves as a cap for a number of years. An alternative approach to using cost data as a basis for price setting is to use information from other utilities to create a benchmark for a price cap. Inter-rate case adjustments for inflation and productivity may allow the regulator to extend the period between rate cases. The goal under this approach would be to increase management's compensation for minimizing costs by reducing the take-backs associated with cost-reassessments in later rate cases, while also allowing ratepayers to benefit from management's duty to operate efficiently.

Typically, regulators have applied price caps to the wires portion of utility operations, but not to power supply. If applied to power supply, a price cap should theoretically align the private with the public interest for least-cost resource decisions, including purchased power. Utilities should more aggressively seek least-cost strategies and negotiate contract terms that allow the utility to reduce costs from those expected.

A price cap approach is so fundamentally different from cost-of-service that it would require a significant commitment by regulators to make this change. Would regulators have access to enough information to implement an equitable price cap? Or would utilities bias the outcome through their superior access to information? Price caps may have significant potential for aligning the public and private interest by allowing a utility to retain cost effectiveness gains for longer periods than under cost-of-service regulation with frequent rate cases.

Moving from a cost-of-service to a price cap regulatory model is a non-trivial initiative. Although price caps may have merit as a way of aligning public and private interest, the adoption of this tool solely to address the misalignments associated with purchased power seems excessive. Price caps for purchased power might look very much like the EPAC mechanism (see section III.C), as they both would set a performance standard while allowing for rate changes driven by fuel price changes. If a regulator combines an energy price adjustment clause with a mechanism that extends the periods between reviews of the productivity factors, then the EPAC provides similar alignment benefits relating to purchased power as a full price cap.

California, Kentucky, Maine, and Massachusetts are states where price caps are used to set transmission and distribution rates.

Under a cost-of-service model, "a" and "b" each equal zero. Revenues are entirely determined by costs.

Under a price cap model, "a" equals the regulator's assessment of efficient costs; "b" equals 1; thereby eliminating the importance of actual costs. If at the starting point "a" (assessment of efficient costs) and "C" (actual "reasonable" costs) are the same, so will be the revenue requirement under either model.

E. Shared savings

To improve the alignment between private and public interests, regulators have sometimes used shared savings approaches. For example, to encourage the greater productivity of the Limerick Nuclear Power Station, in the 1980s the Pennsylvania Public Utility Commission created a sharing system between the utility and its customers for all production in excess of a targeted amount. This occurred within the context of an energy clause that otherwise would have passed on costs and benefits associated with variations in the plant's output to customers. Under the sharing approach, Limerick became one of the world's most productive nuclear power plants, increasing its output by about 50 percent above the targeted levels.

This section discusses two shared savings approaches that compare the cost of purchased power to a benchmark cost. The first compares the purchased power option to the utility build option. The second compares the purchased power option to other price hedges.

1. Comparing buy to build resources

There are potentially two very different types of purchased power transactions. The first is for power that is available at the time the parties negotiate the purchased power agreement. The second is a purchased power agreement whose primary purpose is to allow a developer to finance and construct a new generating facility, such as a wind farm, with output to be sold to the utility. The regulator must address each of these two types of purchased power arrangements when considering the sharing mechanisms discussed in this section.

When considering shared savings, a major question is "savings compared to what?" For purchased power, a natural response would be to compare to a utility-built resource. This would require an up-front net present value comparison of the two approaches similar to what is required for a prudence review.

One-to-one comparisons are difficult when comparing a purchased power agreement for purchased power that is available now at a contracted price to a utility build option. Regulators should not compare a presently available purchased power transaction to a resource that the utility may start to build today at some estimated future price, but that will not be available for at least several years. Regulators need to derive the build resource for comparison purposes from a retrospective look: What would the build cost have been had a resource been built to meet the resource need addressed by the proposed purchased power transaction? The use of this hypothetical or proxy plant adds challenges to the process of creating a benchmark resource. Can the regulator identify actual plants to use for comparative purposes (e.g., plants built by others that have recently come or are now coming into service)? Are the comparative plants utility-built plants with potential concerns of "gold plating"? Or are they "lean and mean" merchant plants built by unregulated power producers? The use of a hypothetical plant may allow regulators to compare the actual transaction to a benchmark with similar characteristics, such as size, fuel source, and lifespan. This approach eliminates many of the uncertainties associated with making long-term resource comparisons. Some uncertainties and comparison issues will continue to exist, particularly if the utility option is for a different technology than is the basis for the purchased power transaction.

In any case, regulators must calculate the present value of the build and buy scenarios, using some possibly contentious discount rate assumption. The build benchmark and the purchased power option will impose different costs on customers over time. As discussed at II.B.1.c, there are differences in risk between utility construction and power purchases. Regulators may wish to consider using different discount rates to calculate the net present value of the two options. Sensitivity analysis would be necessary to test various discount rate assumptions.

The best comparison of a purchased power contract needed to facilitate the financing and construction of a resource whose output is to be purchased is to the utility build option existing at that time. This comparison may already be part of the utility's procurement process. This comparison does not have the timing challenges discussed above and, therefore, could be relatively straightforward.

2. Comparing long-term purchased power to other price hedges

Regulators could consider comparing the purchased power option with other long-term price hedges. The purchased power contract may be a partial hedge (with some energy cost variability) to a full hedge (with prices known in advance) to spot market prices. Hedges are insurance and come at a cost. It would not make sense to compare the purchased power cost experienced by a utility to the spot market price that a utility would have paid for the same power because there is no hedge cost in the spot market and therefore no premium paid.

Regulators may be able to compare the price of the purchased power transaction to other price hedges. These comparisons would occur periodically (e.g., annually) during the contract term of the purchased power contract. Year-ahead hedges are too short to provide a meaningful comparison. Longer-term hedges (e.g., ten-year price strips) are available in some markets. Generally, after about five years, the prices do not change in long-term hedge instruments. When these instruments are available, a formal market (e.g., NYMEX) posts these prices. The regulator could periodically compare the purchased power price to the futures price strip. The regulator would check whether a purchased power contract still produced a least-cost solution compared to currently available hedges. This comparison would produce savings or losses that would be the basis for a shared savings calculation. These strips may not be reasonable benchmarks for comparing the savings or losses associated with a purchased power contract. First, the price of futures is sensitive to several exogenous factors beyond the utility's control (e.g., weather, fuel price, business cycles, and environmental mandates). This type of comparison amounts to second-guessing. Also, there is a lack of comparability between the terms and conditions of a futures contract and a bilateral purchased power agreement (e.g., penalties for non-delivery, locational benefits, and dispatchability). In short, they are simply different instruments.

3. Sharing mechanics

The regulator must make several decisions about how to share the savings between utilities and customers, regardless of how it calculates the savings.

a. Shares

Regulators are constantly awarding "shares" of savings between utilities and ratepayers. Often the sharing is implicit. For example, a utility generally gets to keep 100 percent of its productivity savings between rate cases, while customers receive 100 percent of the savings associated with improved power plant activity when a utility uses a total pass-through mechanism for changes in its energy costs to customers. Both of the aforementioned implicit shared savings mechanisms are symmetrical, with the same party that gets all the savings being responsible for all the losses.

In establishing shares of savings associated with purchased power, the share to the utility should be great enough to offset the Averch-Johnson misalignment, which may cut in either direction. Given the risks associated with resource development shifted to the seller from the utility through a purchased power strategy, the utility's share of earnings need not be as great as from a utility-built resource. The reasonableness of who gets what share may differ from case to case depending upon the facts, including the size of the savings or losses and other regulatory tools used in the jurisdiction. The author has made no effort to quantify the allocation of savings for any particular set of facts in this document. Any rate adjustment based on a difference between either of the two benchmark approaches provides the utility with more compensation the lower the cost of its purchased power.

b. Symmetry

In designing a sharing tool, the regulator must determine whether the tool should apply only to savings, or be symmetrical and apply to losses as well. The sharing discussed above focused on savings and not losses. What if either of the benchmark comparisons produced a loss? For example, it may turn out that the utility could have built a generating station for less than it can currently purchase an equivalent amount of long-term power. Designing the sharing mechanism with symmetry (i.e., so that the utility would share in gains or losses) makes the utility more responsible for the overall cost effectiveness of its least-cost planning program.

Symmetry does not require that the regulator treat losses and gains equally—only that some adjustment be made in both directions. The regulator can design the sharing mechanism so that there is different sharing for losses and gains. Caps can also be included to protect against excessive financial gains or losses.

c. Rate recovery of shares

When comparing a built to a purchased resource, the regulator could have the utility recover the savings or loss through an annualized payment or by capitalizing the net present value of savings and amortizing the savings share. The regulator could implement this sharing in either case through an adjustment to the utility's base rates. When the comparison is to annual price hedges, recovery could occur through an annual surcharge. This difference in recovery mechanics makes a build benchmark approach easier for the regulator and the utility to administer than the price hedge approach.

4. Assessment of sharing approaches

Sharing approaches have the potential to align the private with the public interest for purchased power. Many details would need to be resolved. The comparison to a build resource seems to be more rational than the comparisons to other price hedges, as the build comparisons allow for better matching in the timing of the resources, especially the retrospective look at build options. Utility-built base load resources are also more similar to base-load long-term purchased power contracts than generic price hedges (i.e., price strips) that do not address issues such as deliverability and output flexibility. The use of price hedge comparisons requires making comparisons at different times and for changes that may not be within a utility's control.

The author is unaware of any existing specific shared savings regulatory tools aimed at improving the alignment of the utility's interest with the public interest regarding purchased power.

IV. Conclusions

This paper examined a series of potential tools aimed at improving the alignment of a utility's private interest with the public interest regarding cost-effective long-term purchases. It suggests that regulators may be able to further the public interest by compensating utilities for cost-effective least-cost planning decisions that involve long-term purchased power transactions in ways that are practical and transparent. The following table summarizes the author's judgments of the efficacy of the respective tools. Regulators might choose to use some of these tools in combination (e.g., shared savings with base rate or energy price adjustment cost recovery). Others cannot be combined (e.g., rate of return adjustments and price cap adjustments are mutually inconsistent).

A symmetrical shared savings approach that compares a utility's power purchase proposals to a proxy plant has promise. Avoiding the misalignments associated with traditional energy clauses by applying tools such as base rate purchased power recovery or an energy price adjustment clause also has merit, subject to the availability of production cost modeling resources.

The other approaches discussed in this paper seem to have less merit. Rate-of-return increases for cost-effective purchased power transactions lack precision while potentially increasing the misalignment of interests by increasing the compensation a utility receives on resources it may later build.

Inclusion of capacity costs of a purchased power transaction in rate base aligns the compensation a utility receives for building or buying resources but does not align the utility's interest with least-cost resource planning.

Price caps, although normally applied to transmission and distribution services, could help align public and private interests for purchased power if applied to energy costs. A more targeted solution, however, may be the energy price adjustment tool, which works similarly to price caps for energy costs without requiring that the regulator shift its entire ratemaking paradigm from a cost-of-service approach.

As with any regulatory tool, the devil is in the details. All of the discussed approaches require additional refinement, based upon factors such as local law and regulations, market conditions, the availability of information, and the regulator's resources.

Table 1: Summary of Purchased Power Alignment Tools

	Align Private with Public Interest	Efficiency and Transparency	Comments
Rate of Return Adjustment	Designed to reward cost effectiveness. May negatively contribute to build over buy bias.	Easy to implement but discretionary and not transparent.	Not transparent or predictable. May cause future misalignment.
Include Purchased Power Contract in Rate Base	Places build and buy resources on more par as both are in rate base. No alignment with cost minimization.	Straightforward.	Legal and technical issues to resolve. Lack of cost effectiveness alignment makes it unappealing.
Base Rate or EPAC Cost Recovery	Aligns cost effectiveness but does not address any build-versus-buy bias that may exist.	Requires that the regulator make numerous decisions about production cost model inputs.	Encourages utilities to negotiate and enter cost-effective purchased power transactions with terms that provide opportunities for cost reductions.
Price Cap	Encourages cost effectiveness and eliminates rate base misalignment between build and buy resources.	Requires major change from cost of service regulation.	Worth considering as a total paradigm but not for purchased power alignment alone. Tool usually limited to wires side of electricity business.
Shared Savings	Creates alignment for costs effectiveness. The lower the costs, the greater the compensation to the utility, and the lower the cost to customers. Does not directly address the build-over-buy bias.	Regulators must address major issues such as amount of and caps on sharing.	Comparing purchased power costs to a build proxy seems superior to comparing it to a price hedge. Symmetry in sharing recommended. May be better suited for purchases of currently available power.