BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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RE: THE INVESTIGATION INTO THE POSSIBLE MODIFICATION OF THE RULES CONCERNING INTEGRATED RESOURCE PLANNING, 4 CCR 723-21 AND THE RULES IMPLEMENTING SECTIONS 201 AND 210 PURPA, SMALL POWER PRODUCTION AND COGENERATION FACILITIES, 4 CCR 723-19	)	DOCKET NO. 95R-071E

INITIAL COMMENTS OF THE
VAN HORN CONSULTING GROUP
ON BEHALF OF THE
COLORADO INDEPENDENT ENERGY ASSOCIATION

IN RESPONSE TO THE COMMISSION'S
NOTICE OF PROPOSED RULEMAKING
REGARDING INTEGRATED RESOURCE PLANNING
AND QUALIFYING FACILITY RULES

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INTRODUCTION AND SUMMARY

Van Horn Consulting (VHC) is pleased to provide the Commission with its comments. Our observations are based on our intensive participation in Public Service Company of Colorado's ("PSCo") integrated resource planning (IRP) process in Docket No. 93I-098E and on our familiarity with electric resource planning, energy and environmental regulation, and evolving competition in electricity and gas markets. These comments are submitted on behalf of the Colorado Independent Energy Association ("CIEA"), a non-profit corporation organized for the purpose of promoting non-utility independent power development in Colorado. CIEA's members include firms that own qualifying facilities ("Qfs") that currently sell electric power to PSCo, as well as firms that desire to develop Qfs and independent power projects that will sell their output to Colorado utilities.

The development of Public Service Company of Colorado's Integrated Resource Plan during 1993-1994, represented an important step in electric resource planning in Colorado. Yet, despite considerable public participation and review, the shortcomings and inequities of the initial IRP process favored the incumbent utility over other potential suppliers. As a result, in order to encourage potential suppliers that there can be a fair IRP process in Colorado and to foster the objectives of integrated resource planning, we discuss a number of areas where changes to the current IRP process are clearly warranted. The present IRP and QF rules also require alignment. Rule changes are needed to accomplish the goals of IRP and to comply with the requirements of the *Public Utility Regulatory Policies Act* ("PURPA") and the *Energy Policy Act of 1992* ("EPACT"). If these processes were to continue under current IRP rules, Colorado consumers would be far less likely to maintain reasonable electricity prices and to manage risks, than would be the case if the Commission corrects the procedures and faults in the initial IRP process.

Given the novelty and magnitude of the initial IRP efforts, it is not surprising that some problems were encountered. However, unless the IRP rules are substantially modified a number of the 73 respondents to PSCo's Request for Information (RFI) would be discouraged from taking the time or making the effort to develop bids in Colorado's subsequent IRP proceedings. In addition, modifications of the rules and adjustments to the IRP process can provide an important opportunity to deal simultaneously with two other significant resource planning problems. First, the relationship between the QF and IRP processes should be clarified, which would benefit all parties concerned. Second, the IRP process should provide for all-source bidding in a manner that encourages innovative, diverse resource options and serves as a responsible bridge, but not a barrier, to a more competitive power industry.

Key recommendations to the Commission, based on our participation in PSCo's 1993-1994

IRP process include:

- introduce true all-source bidding with rules that foster fair competition,

- provide preliminary IRP assumptions, evaluation criteria and preliminary IRP results using generic resources in advance of all-source bidding,

- devise and test significantly different plans, rather than examining only variations of the utility's preferred plan,

- apply both near and long-term time horizons for comparing plans, in order to distinguish between near-term and long-term differences,

- represent capital costs consistently so that comparisons between utility resources and other suppliers are not made incorrectly, because of differences in the modeling representations of the costs, rather than in the costs themselves,

- after the 1995 RFP, apply the lessons learned in the 1995 QF bidding process to merge QF acquisition with the IRP process,

- maintain socially desirable programs; encourage supply diversity provided by technologies using renewable fuels and by appropriate demand side measures,

- employ impartial third parties and agreed upon criteria to review the feasibility and viability of all proposed projects, including the utility projects. Use a third party modeling "auditor" to work with the utilities to ensure that all-source bids are modeled and evaluated correctly.

- clarify performance and reliability measures in advance of all-source bidding,

- anticipate the movement to more competitive electricity markets, in order to preserve the goals of IRP,

- initiate Phase Two of this proceeding to implement rule changes based on the lessons learned in the initial IRP process.

Rule changes consistent with these recommendations will help to resolve the current mismatch between IRP objectives, the legal requirements of PURPA to purchase power from Qfs at avoided cost, and the implementation of current rules that could inhibit the realization of IRP objectives over time, unless they are modified.

Because of the movement toward more competitive electricity markets, the Commission should take steps to assure that a modified IRP process is consistent with likely structural changes in electric supply and delivery, recognizing the unique circumstances of the Colorado electricity grid, e.g., the TOT constrained region, and considering existing generating resources and utility assets.

In keeping with the intent of the NOPR, our comments are directed at a broad range of issues, including the sequence of IRP activities and the information requirements needed to elicit competitive bids for generation. After the upcoming hearings, we urge the Commission to proceed to a second phase of this proceeding with a focus on implementing specific rule changes in the Resource Planning Rules, 4 CCR 723-21 and in the Rules Implementing Sections 201 and 210, PURPA, Small Power Production and Cogeneration Facilities, 4 CCR 723-19. When the next phase commences, we are willing to assist the Commission by providing proposed rules for consideration and participating as needed.

OBSERVATIONS AND RECOMMENDATIONS CONCERNING COLORADO'S INTEGRATED RESOURCE PLANNING PROCESS, BASED ON PSCO'S 1993-1994 IRP.

In this section we describe some key lessons from the 1993-1994 IRP process that are needed to improve the process.

<u>Resource Needs Were Inadequately Defined Prior to the RFI Bidding</u>.

If independent resource developers, such as the respondents to Public Service Company's "Request for Infomation" (RFI), are not given sufficient information regarding PSCo's future resource needs, they will not be able to tailor their offers to meet system needs. As a result of incomplete specification, PSCo's 1993-1994 RFI elicited a lesser set of options than should have been available. In addition, other aspects of the RFI evaluation, if continued, would significantly hamper the development of an efficient bidding process in the future.

In fact, there was no real "bidding" in the 1993-1994 IRP process, but "simply a request for information," with "PSCo's sole judgement" being the means of deciding which resources represented the greatest value to Colorado ratepayers. Prior to submitting RFI responses, potential respondents were not given adequate information regarding the types and timing of resources needed. RFI "bidders" were not given useful information that would typically be specified in a bid package or a Request for Proposal. The only information provided in the RFI solicitation was the total Megawatts of capacity additions estimated to be needed for the years 1990-2001 and a transmission map. Information was not given regarding:

- the relative needs for baseload, cycling, or peaking resources,
- the value of having new resources located in the TOT-constrained eastern Colorado

area,

- the value and consequences of different degrees of dispatchability, including the value of being able to operate under automatic dispatch control,

- the most desirable resource locations,

- important transmission constraints and reasonable estimates of transmission costs for resources located in different areas,

- the desirability and consequences of firm pricing and of contract terms of various durations.

The lack of specific information permitted PSCo to reject numerous bids that didn't meet its unrevealed resource requirements and, thereby, gain a competitive advantage for its own plant proposals. The situation clearly becomes unfair when the utility has access to the RFI bid information, and it then revises downward the costs and adjusts the timing of its own preferred project without providing similar opportunities to bidders. PSCo's RFI process did not constitute a level playing field, nor did it elicit the informed bids it might have.

If the IRP rules are not changed to permit a fair competition by requiring utilities to provide adequate information to prospective suppliers, Colorado will not attract bidders and ratepayers will be deprived of potentially lower cost generation suppliers.

Key Planning Assumptions Were Revealed Only After Competing "Bids" Were Received.

Besides not providing sufficient information on resource needs, information on broader resource planning assumptions was not provided to potential competing electric suppliers, i.e., either the RFI bidders or other interested parties, until after the RFI solicitation. PSCo provided this information one month later, when it presented its already-developed, favored plan in the Preliminary IRP. Examples of planning assumptions not available until the Preliminary IRP report was issued include: load and DSM forecasts, present and expected future characteristics of existing generation resources, important transmission and environmental constraints, adopted criteria defining adequate system reliability, the size and timing of power purchases under known contracts, expected QF capacity and its utilization, and DSM/renewable set-asides.

As an example, one controversial planning assumption was PSCo's criteria for reliability used to determine yearly capacity requirements. The reliability criteria used in the IRP were finalized only after the RFI bids were submitted and only after development of the basic plan favored by the utility. The reliability criteria were revised in the middle of the process, were complex and difficult to verify within the allocated IRP schedule and procedures, and might appear to a skeptic to have been revised to support the utility's favored plan. The occurrence of this situation reduced confidence in the process and in its results.

The lack of timely information on general planning assumptions further handicapped bidders relative to PSCo, and fostered unnecessary mistrust and voluminous information requests to clarify the evolving planning assumptions. How could bidders or others not suspect that, perhaps, PSCo was skewing the broader planning assumptions, in order to entrench its own favored options, after the opportunity for competing bidders to develop or revise their proposals had passed? The 1993-1994 IRP process made it very difficult to develop a constructive exchange of ideas among parties regarding planning criteria and assumptions, since lines had already been drawn, once the RFI bids were already submitted, and PSCo's preliminary proposed plan was already published.

PSCo's Evaluation Methods Were Inadequately Delineated in Advance.

In its IRP PSCo used a variety of methods for evaluating resources, starting with the stand-alone characterization and screening of individual resources and proceeding to more complex integrated, cost-driven analyses. These analyses were centered around optimized capacity expansion (PROVIEW) and production cost (PROSCREEN GAF module & MULTISYM) simulations. These simulations used a variety of constraints such as "must-run" dispatch and limits on which specific resources could be combined together and in which years. At various points before, during, and after the capacity expansion optimizations, criteria other than those explicitly included in the optimization were used to eliminate or handicap particular resources. These criteria included additional transmission costs and postulated emission constraints or objectives.

Even though the quantitative evaluation methods and computer models applied by PSCo were similar to those used widely in the industry for electric resource planning, PSCo's process created three very serious problems:

- First, having no advance knowledge of how the complex evaluation process would be conducted and not knowing the criteria that would be applied by PSCo,[1] the RFI "bidders" were substantially handicapped relative to PSCo in developing their "bids" to compete with PSCo's proposed project.

- Second, an inadequate prior understanding and agreement regarding the application of various analysis methods by PSCo engendered suspicion and necessitated voluminous information requests to clarify the methods and to dispute what kinds of analyses were appropriate.

- Third, many parties attempting to follow this process in detail were unconvinced that PSCo's preferred plan would have "won" without the evaluation process being controlled by PSCo. Alternative proposals that might save ratepayers money were presented to the Commission in the IRP hearings. The Commission IRP decision strongly suggests that the Commission could not meaningfully evaluate the competing proposals due to the complexity of the modeling and presentation of the competing alternatives. Even now that a decision has been rendered, it is still not evident that the preferred plant choice actually "won" under PSCo's own, self-selected evaluation criteria, when compared to all alternatives.

<u>After Receiving RFI Bids PSCo Changed its Own "Bid"</u>.

After characterizing its proposed resource additions in the preliminary IRP, PSCo revised the characteristics in the final IRP. The most notable change was a substantial reduction in the estimated capital costs for PSCo's main proposed generating addition, the phased repowering of the Ft. St. Vrain (FSV) facility as a combined cycle unit. PSCo's overall reduction in costs included major increases in estimated hardware costs for FSV, which, however, were more than offset by significant reductions in

[1] As pointed out above, these criteria were not provided prior to the RFI responses, and, moreover, the criteria themselves changed during the course of PSCo's evaluation. In addition, some of the criteria, such as those used to rank and reject proposed projects on the basis of their financial viability, were arbitrary and, in some cases, were arguably applied incorrectly.

estimated indirect construction expenses, gas supply costs, and transmission costs.[2] Thus, not only did PSCo have the advantage of knowing about its own resource needs, planning assumptions, and evaluation methods while the bidders did not, but PSCo also gave itself the opportunity to substantially revise its own "bid" after receiving the RFI responses.[3]

The inconsistent and inequitable treatment of the utility's own proposals vis a vis other proposals is not only perceived to be unfair, but unless the process is modified by revised rules, this inequity hurts any future bidding process and will inhibit the potential success of the IRP process in satisfying its stated objectives.

There Was an Insufficient Definition of IRP Objectives.

PSCo's IRP listed eleven IRP objectives. Among these objectives are minimizing total resource cost, minimizing impacts on electricity prices and the environment, maintaining reliability and resource diversity, ensuring flexibility in the face of future events, and maintaining company financial health.

Although each objective has merit, there were serious problems with the way the objectives were defined and applied:

- With the possible, but unlikely exception of total resource cost (see below), the objectives were not sufficiently defined to indicate how particular resources or multi-resource plans could be evaluated or ranked. Neither the criteria for success nor the priority of objectives were defined -- certainly not at the outset of the IRP process and not much more so by the end of the process.

- Although no one plan could possibly be "best" at achieving each of the objectives, no method was established for weighing or trading off the different objectives. While this would have been a daunting task, the absence of discussion of the threshold for success or for relative importance meant that, in theory, the ranking or comparison of alternatives could be done post hoc, to justify any one of numerous similar plans.

- Only three plans, all very much alike (with FSV accounting for over 50% of resource additions through 2002) were considered in the limited and often qualitative discussion of how these plans would best achieve the objectives.

[2] It is not clear that PSCo's original cost estimate for the Ft. St. Vrain repowering would have passed an investigation and feasibility review of the type applied to the RFI responses.

[3] Again, it should be noted that bidders were asked only for a request for information, not for a request for proposals or for formal bids.

Thus, no consistent method for determining how well different plans met the overall stated objectives was established. Neither before or after the RFI, neither before or after PSCo presented its favored plan, nor before or after different resources and plans were evaluated, were consistent comparisons defined or expressed. PSCo had broad freedom, after all "bids" were in, to define how the different objectives were to be measured and weighted, with the partial exception of Total Resource Costs.

In summary, parties interested in the IRP process had almost no idea how the objectives were to be measured or traded off, either at the outset or after all was said and done. However, no one who paid attention along the way had much doubt about what the final result would be.

"Total Resource Cost" Is An Unclear Measure, and It Was Used Inappropriately in Comparing Plans.

Among the various IRP objectives, minimization of total resource cost ("TRC", including utility and customer costs, and, theoretically, including societal costs) was apparently given the greatest weight. The optimization process was the main vehicle for justifying the combination of the different resource options into a preferred plan, and TRC played the dominant role in the optimization process for each alternate plan. This relative importance of TRC versus other objectives in both developing plans and comparing plans should have been clarified at the outset.

As defined and used in the IRP process, TRC had at least three very serious problems:

1. The Use of Economic Carrying Charges to Calculate the TRC Understated the Costs of Utility Owned Resources.

The first major problem with TRC as used in the IRP process is that it represented capital costs for company-owned (rate-based) resources as back-loaded economic carrying charges (ECC) levelized over time, rather than as actual front-loaded year by year revenues required from ratepayers to recover capital costs. The ECC in any year theoretically represents the added (annualized) capital cost for building any particular resource in a given year relative to delaying that same resource, basically giving levelized real carrying charges, escalating in current year dollars. Because this results in back-loaded costs (expressed in current year dollars, flat costs in constant dollars), the ECC substantially understates the cost of a 30-year resource when costs are viewed over a 10 or 20 year planning period, and the ECC only gives the same net present value as the actual costs when the entire resource life is considered. This contrasts with the representation of capacity costs for most independent power projects, which were represented in PSCo's models as operating costs using the projected year by year stream of payments. This method favors utility-owned resources and disadvantaged independent power projects, all else being equal. The implications of comparing company-owned resources and plans incorporating these resources, based on artificial back-loaded capital cost recovery were not revealed in a timely manner in the IRP process and were never agreed to by most parties outside of PSCo.

2. End Effects Far in the Future Shifted the Overall TRC for Different Plans.

The second major problem with TRC as calculated is that it was based on not only the 20 year modeled planning period, but it also included an infinite "end effects" period. The end effects costs had a substantial impact on the overall TRC for the different plans examined. It was the lower end effects costs that caused the preferred plan to "beat" other plans that had lower TRC over the 20 year planning period (and much lower TRC over the first 10 years). This means that the benefits of the preferred plan, relative to other plans, will not occur until late in the planning period.

We have an imprecise idea of what will happen beyond 10 years, let alone 20 years. It is inappropriate to give so much weight to an infinite end effects period. A simplified methodology was used to calculate the "end effects" costs compared to the methodology applied for the first 20 years, further discounting the credibility of using different end effects costs to distinguish among candidate plans. The end effects costing using the PROSCREEN methodology assumed that resources in place in the last year of the planning period (2012) replace themselves in-kind indefinitely and that the last year's dispatch of the different kinds of resources is likewise perpetuated identically and indefinitely. This gives considerable undue weight to the modelled system configuration in year 2012, ignores the potential for future resource opportunities and resource combinations, and is strongly influenced by the absolute and relative escalation rates assumed for the different cost categories (e.g., capital, O&M, gas, coal), which are applied as constants to the indefinitely self-replicating capacity mix, regardless of possible interactions.

3. Total Resource Costs in the 10-20 Year Period Are More Uncertain Than in the First 10 Years, and this Uncertainty Should Have Been Reflected.

Costs in the 10-20 year period are more uncertain than those for the first 10 years, while costs estimated beyond 20 years are still more uncertain. However, costs beyond 10 years were calculated for inclusion in TRC using the same level of calculational detail as was used for the first ten years. Although these later costs are discounted to account for the time value of money, they are not discounted to account for their increasing uncertainty. Hence, the calculation of TRC almost certainly gives too much emphasis to the second ten years, whose costs are added to costs from the first ten years using only economic discounting at the weighted average cost of capital. In the later years of the capacity expansion simulation, the assumed resources available are generally more uncertain and would be available to all plans regardless of differences among those plans in the earlier years. Therefore, cost differences among plans in the 10-20 year period are influenced mainly by how precisely the accumulated, "lumpy" capacity additions among the different plans fit the very uncertain, but smooth long-term load forecast in each year, instead of being determined by the particular long-term resources available in each alternate plan.

For example, due to the sequence of capacity additions and constraints, the "small NUG" plan ended up having about 217 more MW added at Pawnee than the "preferred plan" by the end of the planning period. This result was stated by PSCo to require $66 million more transmission facilities, even though the two extra NUGs added in the Pawnee area under the small NUG plan only amount to about 85 MW by themselves. Also, the small NUG plan ended up with about 100 more MW overall by the last year of the planning period, which entails additional capacity costs. How much weight should we give to long term (10-20 year) cost distinctions among plans, when these distinctions are driven mainly by differences in the sequence in which long-term, lumpy resource additions are selected from a common long-term resource pool to fit an uncertain load forecast? The situation is exacerbated when this sequence of additions is further restricted by constraints on which resources can be taken in combination with others and in which years.

A popular depiction of "Chaos Theory" uses the example where, due to myriad interactions that are poorly understood or unpredictable ("random"), a butterfly flapping its wings in, say, Hawaii could lead to a storm in Denver. The implication is that because this "causal" effect is intermediated by so many "random" interactions, we could never in reality predict the storm, even if we knew everything about the butterfly. Sometimes we can step back, evaluate, and convince ourselves that the near-term differences between two alternate plans really are the cause of long-term differences calculated via computer models, but sometimes we cannot. If not, just as we are probably fooling ourselves into believing that we can predict a storm based on the butterfly's behavior, some minute differences between two plans do not provide a sound basis for choosing one over the other. This was the case for several of the comparisons of alternative and preferred plans, where the differences were greatest far in the future, and, yet, were relied upon to claim a preference for one plan over another.

The Evaluation of Uncertainty Was Inadequate and Focused Only On Similar Plans that All Included PSCo's Preferred Resource.

It is undisputed that electric resource planning must consider a considerable range of uncertain future conditions and good plans should be expected to perform acceptably over a range of future conditions. Of the eleven objectives PSCo established for its IRP, one objective directly relates to performance of plans under uncertainty ("ensure flexibility for responding to future unknowns"); another objective has as its major rationale the assurance of adequate performance across a range of uncertainties ("use a diverse mix of resources and technologies"), and another objective implies that the IRP plan should possess the ability to perform adequately over a range of uncertainties ("develop a sustainable plan").

Unfortunately, there was no clear delineation, at the start of the IRP process, of what key uncertainties should be considered, or what weight each should receive in meeting these objectives. The main sensitivity analyses in the IRP were described only well after the RFI bids were submitted, well after PSCo had presented its own favored plan, and even after the analysis and rejection of various options was well underway.

This after-the-fact process presented several problems. First, important uncertainties were not considered adequately. How about uncertain load growth (which the IRP rules specifically require be considered for the alternative plans)? What about technology improvements and competition leading to better options in the future, potentially stranding major capital investments? How about scrutinizing more carefully a shorter planning horizon, more in line with what is really going in electricity planning and energy markets today.

The unavailability of information from the preliminary IRP process prior to the RFI and the imprecise intent of the RFI limited the ability of the RFI respondents to propose projects that would best address key concerns about risks. The fact that the uncertainty analysis methods and results were presented only after the RFI bids were submitted and PSCo's favored plan was presented, created legitimate concern that the sensitivity analysis could be tilted in favor of PSCo's projects. Furthermore, the uncertainty analysis that was performed was of limited value, because all of the plans examined (Section 2.15.4 of Final IRP) were really very similar, with FSV repowering accounting for over 50%

of resource additions through year 2002. Different kinds of plans will perform differently under different conditions. However, if uncertainty analysis focuses only on a narrow range of plans, as it did in the current IRP process, it does not tell us much.[4]

The Criteria for Feasibility Analysis Were Arbitrary and Used a Cookie-cutter Approach to Reject Some Viable RFI Offers.

PSCo and its contractors conducted feasibility analyses of various RFI offers. This led to some offers being substantially discounted or summarily rejected, because of developer inexperience, technological or permitting hurdles, or supposed "under-pricing." This judgmental review also led to significant cost adders being applied to some RFI offers, after the fact, for such costs as imputed transmission additions.

Feasibility analysis can be valuable, but who is to conduct the analysis and under what guidelines? Should PSCo's own proposed projects be treated in the same manner? -- which they were not. Should not someone besides PSCo evaluate Fort St. Vrain retrofit feasibility and performance assumptions; FSV capital costs including hardware, labor, and indirect costs; the allocation of future gas supply costs to FSV; and transmission costs for PSCo-proposed resources versus other resources? If PSCo is allowed to judgmentally determine the feasibility and cost for its own project and also for all the bids, is there, in fact, a competitive bidding process or is that process a subterfuge? In PSCo's initial IRP the RFI process was poorly executed and must be redesigned, if it is to be meaningful.

[4]The IRP really never dealt with the issue of how to compare firm versus non-firm priced resources. In fact, the limited "high capital cost" and "high fuel prices" sensitivities that were examined showed the "preferred plan" not to perform well relative to some other plans. If these other plans had not included FSV (which was slightly delayed in those cases), the alternate plans would have performed even better. The unanswered question is, how much weight was given or should be given to these and other sensitivities?

RECOMMENDATIONS AND AREAS OF CONCERN FOR PROPOSED RULE MODIFICATIONS.

Specific goals for improving the IRP process should be to:

- fix problems encountered in the initial IRP,
- introduce true all-source bidding with rules that foster fair competition,
- maximize opportunities for constructive cooperation and exchange of ideas,
- consider mechanisms for encouraging competition consistent with evolving energy markets and the particular circumstances in Colorado,
- provide mechanisms for promoting long-term social objectives such as environmental protection, demand-side measures and efficient energy use, and the use of renewable resources,
- integrate the IRP and QF processes in a workable manner that preserves the objectives of PURPA,
- do all of this in a manner that can evolve over time under changing priorities concerning competition, social objectives that are not adequately promoted under competition, and reduced regulatory oversight of some previously regulated functions.

Recommended areas for key improvements are discussed below.

1. Introduce All-Source Bidding with Rules That Foster Fair Competition.

The IRP should require all-source bidding, in which all potential bidders are provided with sufficient information on resource needs, planning assumptions, and evaluation criteria to develop competitive and innovative proposals that are responsive to the needs of the overall electric system and Colorado customers. Bidding and any opportunities to subsequently fine tune selected bids should be extended fairly to include utilities and independents alike. Many states and utilities have prepared and evaluated comprehensive bid packages to solicit competitive offers.

Winning bidders, including the utility, if its bid is selected, must live by the terms reflected in the bid. Under the current process the utility has an incentive to low-ball its own cost projections, since it may later recover prudently incurred cost increases from ratepayers by requesting relief from the Commission. In such a situation third-party bidders bear a greater downside risk than the utility, since they are forced to internalize the uncertainty of cost escalations in their bids. At the same time, non-utility bidders can reap greater profits than a regulated utility, and the utility should not be forced to bear undue downside risk, while earning only its regulated return. Various means to make the upside and downside risks borne by utilities and other bidders more symmetric, while protecting ratepayers, and methods for evaluating the risks associated with firm price bids versus non-firm price bids should be discussed in revising the rules.

Other issues that must be dealt with include defining criteria for triggering the bidding process in between formal IRP proceedings. For example, if the utility wants to add resources to prevent customer bypass, this situation should trigger a bid opportunity if the excess power from the resource will be sold into the transmission grid. A meaningful, all-source process that cannot be improperly circumvented is needed to encourage competition and meet the intended objectives of integrated resource planning.

2. Provide Preliminary IRP Assumptions, Evaluation Criteria and Results in Advance of All-Source Bidding.

A revamped preliminary IRP should be required that describes resource needs, planning assumptions, and key evaluation methods and criteria. This document would be a part of the all-source bid solicitation and would also provide two major benefits conspicuously lacking in the recent IRP.

First, timely and more complete information in a redesigned preliminary IRP would partially level the playing field by providing various participants with better information prior to bidding.

Second, the perspectives and expertise of the various parties, especially the utility, could be used in a more cooperative, less contentious environment to agree on planning assumptions, methods, and resource needs BEFORE the bidding process, and BEFORE various parties have committed to their positions.[5] The public process should be reformed to more closely resemble a bid conference, where prospective bidders have the opportunity to request more detailed information about the utility's resource needs, including model runs. This process needs to take place before the bids are submitted. A re-ordered, well-managed process should require less time and effort than the current process. Once the bids (including PSCo's proposals) have been submitted the potential for constructive cooperation regarding complex and judgmental planning issues is reduced. IRP Rule 5.12 requires that the utility justify all data and assumptions. For data and assumptions not dependent on particular competing proposals for future resources, it makes sense to take care of the most problematic aspects of justification before getting into the bidding and evaluation.

[5] We consider this re-ordering of the IRP process to be essential for IRP to satisfy its objectives.

Among other things, the preliminary IRP should describe:

- peak and energy load forecasts,

- historical and projected future availability and performance of existing system resources, including power contracts, QFs, demand side measures, and system generating units,

- reliability requirements/objectives and the method for measuring their achievement, including the contribution of individual resources,

- important transmission needs and constraints, especially as they affect siting and costs of future resources in different locations,

- operational definitions of IRP planning objectives (how, unambiguously, do we measure their achievement) and their interrelationships (e.g., relative weighing, quantification, trade-offs, hierarchy of objectives, etc),

- key uncertainties ("sensitivities") for which different resources and plans are to be evaluated (for example, high fuel prices, high capital costs, low loads, future toxics/CO_2 regulations, possible future resource options and improved technologies). The current IRP rules are vague about what uncertainties should be considered, but do call for evaluation of the different plans investigated under the different load forecasts, of which at least three (high, low, most likely) are required, although this was not done in the recent IRP.

- technology, cost and performance characteristics of generic resources that could be used in the preliminary IRP to develop plan attributes, including likely resource needs that would be provided along with other bid information.

There need to be stronger guarantees that the subsequent plan development/evaluation process treats all resource options fairly and consistently as required under the IRP Rules, following guidelines laid out in the preliminary IRP, which might include guidelines for subsequent information requests and model runs. If key data, assumptions, and methods are documented and agreed to before the bidding, there is less likelihood of voluminous information requests afterwards.

Because the utility would be a potential competing bidder, specific characteristics of a proposed project (such as a new generating unit proposed by the utility) would NOT be included in the preliminary IRP, to preserve confidentiality of information until after the bidding. Therefore, future system performance and resource requirements would be projected using generic resource characteristics, tailored to the specific utility system needs developed concurrently in the preliminary

IRP.[6]

When the bids are evaluated, all proposals must be evaluated against the publicly announced criteria, which should not be fashioned after the fact. Moreover, the utility should not be permitted to lower its own bid during the evaluation process, unless other bidders are likewise given the opportunity to refashion their bids.

3. Devise and Test Significantly Different Plans, Rather than Examining Only Variations of the Preferred Plan.

Before deciding on a preferred resource plan, the IRP should consider, with adequate care and openness, several substantially different plans. If all plans evaluated and reported on in any detail represent only minor variations on a single favored plan, we can not learn much about how that plan compares to other plans, or how good that plan really is. This is particularly true for evaluation of uncertainties. The main thing we learn from sensitivity analysis is how the different plans compare across different uncertain future conditions, and if any plans have important Achilles' heels. If the evaluation of uncertainty does not include substantially different plans, the uncertainty exercise is hollow. In the current IRP, all plans included in the uncertainty analysis were similar, with Ft. St. Vrain repowering comprising over 50 percent of resources added through 2002.

4. Apply Both Near and Long-Term Time Horizons for Comparing Plans, in order to Distinguish Between Near-Term and Long-Term Differences.

The performance of candidate plans, especially their costs, should be reported for the 0-10 year, 10-20 year, and "end- effects" (beyond 20 year) periods, not just for all three periods combined. The relative performance of different plans in the different time periods should be compared, and plan optimization should not include end-effect costs as they were calculated during the current process. The end-effects calculation should merely account for demonstrable inequalities in the remaining resource value represented by the different candidate plans as of the last year of the planning period, rather than perpetuating minute differences in the last year that can swing the apparent value of one plan versus another, when, in reality, there is no measurable difference.[7]

[6] Doing away with the preliminary IRP, as has been suggested, is not a good idea. The interests of consumers and others in Colorado are best served not by protecting the utility from the participation of others during the planning and resource procurement process, but by achieving this participation in a more timely and constructive manner.

[7] Little or no weight should be attached to differences in end-effects costs that are

If plan evaluation and optimization focuses on the 20 year time horizon and if this time horizon produces a substantially different ranking of plans than the 10-year horizon, then the 20-year result should only be given substantial weight if the factors leading to contradiction of the 10-year results can be shown to be reasonable and are specifically attributable to properties inherent in the different plans.[8]

5. Represent Capital Costs Consistently So That Comparisons Between Utility Resources and Other Suppliers Are Not Made Incorrectly Because of Differences in the Modeling Representations of the Costs, Rather than Differences in the Costs Themselves.

When different plans are compared based on their costs over the 10 and 20 year time horizons, capital costs should be represented as they would actually occur (i.e., as they would be recovered from ratepayers) on a year by year basis. Representing some costs on a year by year basis, while representing others by economic carrying charges, biases the comparison.

6. After the 1995 RFP, Apply the Lessons Learned in the 1995 QF Bidding Process to Merge QF Acquisition With the IRP Process.

After the completion of the 1995 QF RFP bidding process, the lessons learned in this process should permit QF acquisition to be merged with the IRP process, as part of future all-source bidding. In the future the avoided cost used to determine QF payments would be developed within the IRP process. Various options to satisfy the intent of PURPA to encourage diverse, small power production facilities and cogeneration should be considered, such as giving QFs appropriate credits/benefits or diversity set asides in the IRP bidding process. The 20 percent QF "target" discussed in the Commission's QF bidding decision was never required or intended under PURPA and is not needed, if QFs are included in an overall resource bidding process intended to benefit ratepayers by acquiring competitive resources.

7. Maintain Socially Desirable Programs; Encourage Supply Diversity Provided by Technologies Using Renewable Fuels and by Appropriate Demand Side Measures.

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calculated assuming that final year resources and system dispatch are replicated indefinitely under generic cost escalation factors -- this is not useful and is not required under existing IRP rules.

[8] Only when the elements giving rise to the differences are distinguishable between two plans should weight be accorded to minor differences between otherwise equivalent plans.

One clear intent of the present IRP process is to ensure supply diversity including technologies using renewable fuels, to foster appropriate demand side measures and promote environmental benefits. These goals can be continued via set-asides specifying the quantity needed to meet diversity and other IRP goals. These set-asides could be filled by PSCo or by other parties out-bidding PSCo to fill the set-asides. If PSCo's options are not outbid, PSCo would meet the set-aside goals and would get assured cost-recovery via rates in a manner intended to have a neutral impact on PSCo's competitiveness. Any demand side or diverse technology/renewable supply options acquired in the overall open bidding process could be counted against the set aside goals. The set-aside quantities and any bidding adders or discounts applied to demand side and diversity/renewable supply side options could be revisited over time.

We stress the importance of maintaining these IRP goals, simply because the movement to competition means that short-term competitive conditions should not be permitted to inhibit the development and commercialization of diverse ways of meeting our energy needs over the long-term.

8. Employ Impartial Third Parties and Agreed Upon Criteria to Review the Feasibility and Viability of All Proposed Projects, Including Utility Projects. Use a third party modeling "auditor" to work with the utilities to ensure that all-source bids are modeled and evaluated correctly..

An independent third party should review bids for technical and financial feasibility and viability, including utility bids. The resource evaluation process should be designed to incorporate third party review at key milestones within the process, based on evaluation and review procedures developed ahead of time, as part of the preliminary IRP. An independent third party should also review the modelling procedures and monitor the analysis process carried out by the utility to compare resources. This "auditor" would provide a report to the Commission and interested parties, in order to address the complexities and resolve many of the substantial doubts about the treatment of the bids and the validity of the comparisons that arose throughout the 1993-1994 IRP process.

9. Clarify Performance/Reliability Measures in Advance of All-Source Bidding.

How should utility and non-utility performance requirements be equalized? In an open bidding and evaluation process, there is no need to treat utility and non-utility resource proposals differently. In characterizing resource need (prior to the bidding) and in evaluating bids, proposed utility and non-utility resources alike should be assigned to categories based on their characteristics, including those affecting a resource's contribution to system reliability, such as dispatchability and location. To the extent that the preliminary IRP finds a greater need or value for resources with dispatchability or certain locations, this information should be disclosed to prospective bidders.

The independent third party technical/financial review should evaluate the risk of non-performance for utility and non-utility projects alike. The utility should be given no additional, and no less, flexibility regarding deadlines and costs. The criteria for choosing resources having such flexibility, and the penalties for allowing such flexibility, should be the same regardless of ownership.

Who should bear the risk of non-performance? For utility projects this risk has historically been borne by both ratepayers and shareholders, often determined after the fact. For future utility and non-utility resources, acquired by bidding, risk allocation can made on an up-front basis, selecting from a varied set of bids with different risk characteristics. To the extent that contract prices are firm and penalties for non-performance are high, the ratepayer may bear less risk than historically. When a utility plant has a delayed in-service date, poor availability, or higher than anticipated costs, the consequences for the customer are no less severe than if a non-utility project were involved. The same applies, if there is a supply interruption. Ratepayer financial risk is increased any power producer is allowed to recover additional costs after the fact.

10. <u>Anticipate the Movement to Competitive Electricity Markets, In Order to Preserve the Goals of IRP</u>.

"Let the market decide" is a refrain that will have important implications for IRP. In a fully competitive industry the necessity for an IRP process and the ability to achieve some of the goals of IRP are in question. However, regardless of how fast competition arrives and despite the several forms a restructured electric industry might take, issues concerning possible "stranded costs," the necessity for a protracted IRP and bidding process, and the maintenance of the goals of the IRP process will each need to be addressed. An open, all source bidding process developed as part of the IRP will better position Colorado to achieve the goals of IRP and to prepare for the transition into a more competitive electric marketplace. Correcting today's regulatory rules in the light of emerging competition, taking advantage of what we have learned in the initial IRP, is a necessary first step towards realizing consumer benefits from both the IRP process and from the emerging competitive marketplace.

11. <u>Initiate Phase Two of this Proceeding to Implement Rule Changes Based on the Lessons Learned in the Initial IRP Process</u>.

There is no question that competition in energy markets can benefit ratepayers. In the last IRP, the RFI bids were followed by cost reductions associated with PSCo's preferred project, the repowering of Ft. St. Vrain. The task this Commission faces is to redesign the IRP rules to encourage competitors to bid again by creating a more equitable process that could, in fact, achieve the goals intended for integrated resource planning.

However, it is unlikely that independent third parties will incur the expense to prepare future bids, unless the rules are redesigned to rectify the shortcomings we have identified and described in these comments. When Phase Two commences, we are willing to assist the Commission by providing proposed rules for consideration, by participating in a Working Group, or by contributing otherwise.