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# **Analysis of 2001-2002 Power Supply Outlook**

**Northwest Power Planning Council**

**April 4, 2001**

## Executive Summary

The ongoing drought has focused concerns about the adequacy of the region's power supply for the coming summer, fall and winter. Operational strategies for the Columbia/Snake river hydropower system are a key component of managing through this year with the objectives of:

- Satisfying electricity demand through this spring and summer;
- Achieving reasonable summer flows for salmon migration;
- Not significantly worsening fall and winter reliability and the ability to meet Biological Opinion (BiOp) reservoir target elevations in 2002; and
- Limiting the impacts of wholesale power purchase costs on the region's economy and the financial condition of the region's utilities.

To assess the options available to the region, the Council has analyzed several alternatives for the operation of the power system over the coming year. The analysis was done in two stages. The first focused on this spring and summer for two water scenarios -- 1977 water and 1944 water. These years bracket the current runoff volume forecast for 2001. For each of these water years, several operating strategies were evaluated. They include: running the hydropower system to the Biological Opinion constraints for spill and flows; maintaining spill while drafting the system deeper to meet loads; and three strategies that involve significant reductions in spill combined with limited use of deeper drafts, with the objective of achieving BiOp reservoir elevations by the end of August. The analysis looked at such metrics as the amount of curtailment that could be experienced, the cost of purchased power to address any curtailment, end-of-August reservoir elevations, and spring and summer flows.

The second stage of the analysis focused on the operation of the system through the fall and winter with the starting elevation of the reservoirs in September being the primary variable. This analysis was done probabilistically with uncertainty about fall and winter water conditions, temperatures and forced outages of thermal units. The analysis looked at the probability and magnitude of load loss during the winter period and April 2002 reservoir elevations.

The conclusions drawn from this analysis are:

1. Operating the hydropower system to the BiOp targets for spill and flows would lead to either significant curtailments and/or very large purchased power costs this summer.
2. Operations this spring and summer that leave reservoirs at the end of August at elevations significantly below BiOp elevations expose the region to significantly increased probability of power supply inadequacy next winter. In addition, such operations would result in a significant probability that April 2002 reservoir elevations will be well below BiOp elevations, thereby reducing spring flows for salmon.
3. The only alternatives we see that both avoid curtailments and/or large purchased power costs this summer AND return reservoirs to BiOp elevations by the end of August involve substantial reduction in spill and limited drafting of reservoirs beyond BiOp elevations. Reductions in spill can be restored by purchases, reductions in load and additional generation. Alternatives that significantly reduce spill have the additional advantage of reducing market prices this summer and bringing additional income into the region in the form of dollars, returned energy next fall and winter, or both.

4. Decisions need to be made now, but they can be revisited periodically as the spring and summer unfold. The spill season begins in April. By that time, we will have relatively little additional information about how the rest of the spring and summer are going to unfold. From the power supply standpoint, a prudent approach would be to significantly reduce spring spill. If conditions improve through the spring, it may be possible to restore some spill. If, instead, we were to opt to maintain spill or reduce it only slightly in the spring and if conditions do not improve, that spill energy would be lost to the system and would necessitate more stringent and potentially very expensive measures later on.
5. The potential for power supply problems this summer and next winter and the probable high cost of power call for continued and increased attention to implementing load reduction, conservation and new generation.

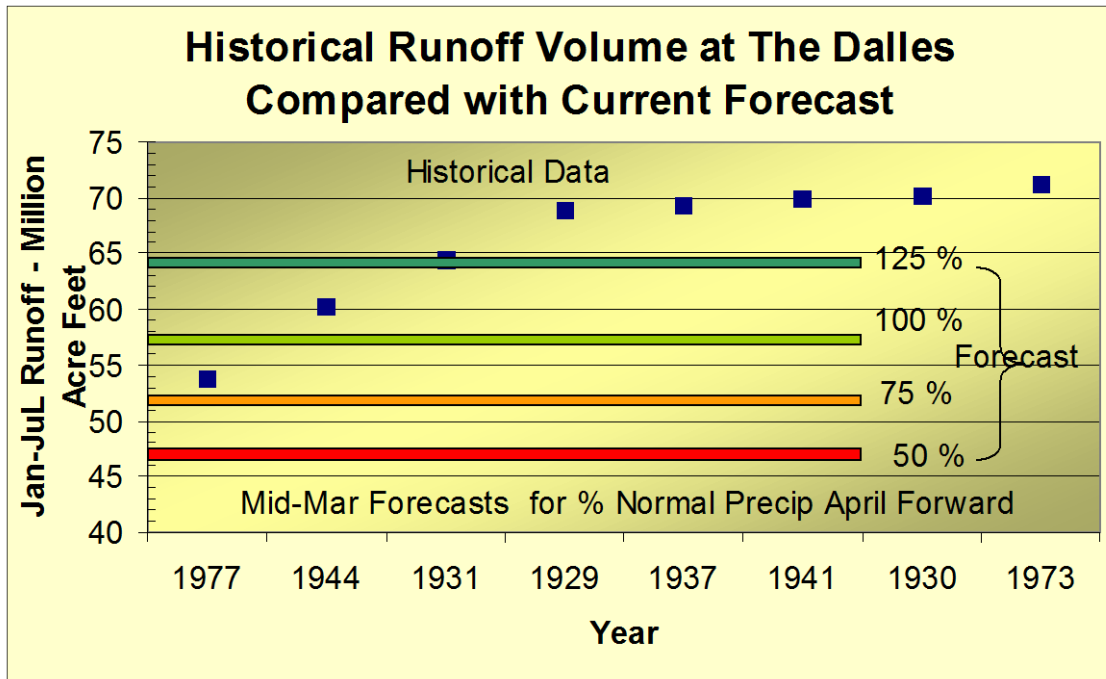
## Introduction

The runoff forecast for 2001 continues to degrade. The January-through-July forecast released March 15<sup>th</sup> is 57.6 million acre feet (MAF) at The Dalles Dam.<sup>1</sup> The mid-March forecast for runoff volume at The Dalles compared with the eight lowest years in the 60-year historic record is shown in Figure 1. The most often quoted forecast assumes 75 percent of normal precipitation for the last two weeks of March and 100 percent of normal precipitation from April 1<sup>st</sup> on. However, alternative forecasts are made for higher and lower percentages of normal April-July precipitation. As Figure 1 shows, if the April through July precipitation is 75 percent of normal, the runoff volume would be less than the 1977 volume, the lowest on record. While National Weather Service personnel to whom we have talked do not believe April through July precipitation that is 50 percent of normal is very likely, the possibility of runoff as low or somewhat lower than 1977 is quite possible.

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<sup>1</sup> The April “early bird” forecast has come in at 55.7 MAF.

Figure 1



These conditions raise obvious concerns about whether the Northwest power system can meet loads through this summer and next winter and satisfy the other demands placed on it.

### Objectives

In view of the very poor water conditions facing the region and the continuing power crisis in California, the Council has undertaken an analysis with the objective of identifying strategies that:

- Satisfy electricity demand through this spring and summer;
- Achieve reasonable spring and summer conditions for salmon migration, given the circumstances;
- Do not significantly worsen fall and winter reliability and the ability to meet Biological Opinion reservoir target elevations in 2002; and
- Limit the impacts of wholesale power purchase costs on the region's economy and the financial condition of the region's utilities.

### Tools

The tools that the region has at its disposal to meet these objectives are:

- Use of "emergency" hydro. Emergency hydro is defined as additional energy that can be generated by drafting reservoirs below elevations intended to increase the likelihood of meeting spring and summer BiOp flows for salmon. The risk in using emergency hydro is that we may take reservoirs so low that summer flows are affected and end-of-August elevations have a significant adverse effect on fall and winter reliability.
- Reducing spill. Spill is water that is passed over the dams, not passed through turbines. Consequently, spilled water produces no energy. Spill is an element of the BiOp and is

also an element of the FERC-sanctioned agreements governing the operation of non-federal projects on the Columbia. The risk in reducing spill is the possible impact on survival of in-river downstream juvenile migrants.<sup>2</sup>

- Purchase of imported power. To the extent that we can purchase power, potential deficits can be reduced or eliminated and water can be retained in the reservoirs. The availability and price of imports is problematic this year. Physically, there ought to be imports available in off-peak periods. However, this year the price may be prohibitive. The costs of purchased power work their way into retail rates with adverse impacts on the regional economy. In addition, Bonneville's financial position is particularly vulnerable this year. High purchase power costs could imperil Bonneville's ability to make its Treasury payment and maintain necessary operating reserves through the fall.
- Additional in-region "emergency generation." Several utilities in the region have or are in the process of installing emergency generation. These are typically groups of diesel fuel or natural gas-fired reciprocating engines -- "Diesel Farms." Others have turned to small, single cycle gas turbines, some older used units, others new. In addition there is some ability to utilize existing industrial and large commercial backup generation. These are relatively small in utility terms, but can add up in aggregate. To the extent these units can be acquired and operated at costs less than the cost of purchased power, they can offset expensive purchases or use of the other alternatives. The downside is the potential air quality impacts associated with these typically comparatively high emissions units.
- Voluntary or purchased load reduction. This can take several forms. One is investment in traditional conservation -- the more efficient use of electricity. This has the advantage of reducing electricity use while not impacting productivity or lifestyle. Certainly a lesson of the past year is that sustained investment in conservation is important. However, there is relatively little that can be implemented by this summer. The other approach is curtailment -- reducing or eliminating some uses of electricity. This can be voluntary, such as elimination of unnecessary decorative lighting and signage; turning off lights and appliances when not in use, and so on. Or it can be purchased curtailment. The most prominent example of this has been the aluminum industry, where most plants are now being paid not to operate. The amount of the payment is less than the cost of the power to serve them. This approach has other applications as in irrigated agriculture and other industries.

## Analytical Approach

In this analysis, the Council used its GENESYS model of the Northwest power system. That model is described in detail in the Council's March 2000 power supply adequacy study.<sup>3</sup> GENESYS treats the region as a whole, but does simulate the transmission constraints into the region and between the Eastern and Western parts of the Northwest. Individual utilities or control areas are not modeled. The region modeled included all of Montana, Oregon, Idaho, and Washington so that results could be directly compared with information from the Northwest Power Pool. Regional loads were reduced to account for the recent reductions in direct service industrial (DSI) load. It was assumed that there was approximately 500 megawatts of DSI load still operating. Further

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<sup>2</sup> Most smolts in the Snake River will be barged this year, but some remain in-river. There is no barging in the Columbia main stem upstream of McNary.

<sup>3</sup> Power Supply Adequacy...

reductions in DSI load are possible. In addition, there are some additional industrial closures that may not be reflected in the analysis. The model also incorporates known "emergency" generation such as the "diesel farm" installations that several regional utilities have undertaken. The potential for imports from outside the region – British Columbia, California and the Desert Southwest – is represented by seasonal supply curves that are estimated from available data and consultations with informed persons in the affected regions.

### ***Stage 1 - March through August 2001***

The analysis was approached in two stages. The first concentrated on the March-through-August period. The analysis began with the reservoirs at their actual March 1<sup>st</sup> elevations. Typically in analyses of this sort, important variables like hydro conditions, temperatures and, therefore, electricity loads, and forced outages of power plants are treated probabilistically. Several hundred simulations or "games" are run where the water conditions, temperatures and forced outages are sampled according to their probability of occurrence. By analyzing the results of these hundreds of games we can estimate the probabilities of load-resource imbalances and meeting reservoir elevation and river flow targets. However, because there are so few years in the 60-year record of hydro conditions with runoff volumes like the current forecast and only one with a lower runoff, we have chosen to do scenario analysis using 1944 and 1977 water conditions. The analysis is limited to monthly energy analysis due to difficulties in modeling sub-daily operations with this year's reservoir and water conditions. Average temperatures and expected operation of thermal units were used.<sup>4</sup> The actual maintenance schedules of thermal generating units are now commercially sensitive information and not easily obtained. For this analysis, planned maintenance of thermal units was scheduled into May, June and early July as has historically been the case.

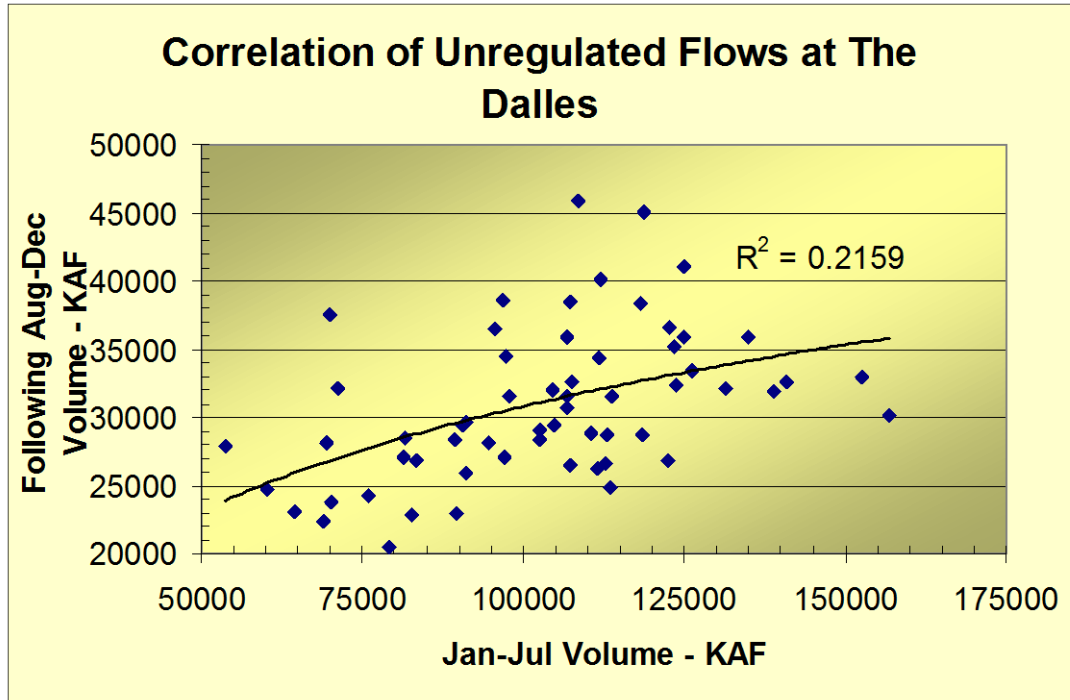
The first stage looked at various operating strategies for the spring and summer primarily involving emergency hydropower and reductions in spill. Purchases were not evaluated explicitly because of the uncertainty of the availability of purchases this spring and summer (California is experiencing rolling blackouts as this is being written, a time when peak loads in the state are approximately 60 percent of what can be expected this summer) and their expected extremely high cost. However, depending on availability, purchases could substitute for spill reduction or could be used to restore reservoir levels after emergency hydro operations. Council staff is attempting to get information regarding aggregate firm import commitments that Northwest utilities may have. The analysis will be updated if this information becomes available. The analysis focused on the level of potential curtailment, the effect on spring and summer flows, and the end-of-August reservoir elevations.

### ***Stage 2 -- September 2001 through February 2002***

The second stage of the analysis focused on the ability of the region to meet loads through the ensuing fall and winter for different reservoir elevations at the beginning of September. For this part of the analysis, a set of hydro conditions corresponding to the lower two thirds of the water years (runoff volumes less than 114 MAF) were used. This is because there appears to be a correlation, albeit very weak, between the January-through-July streamflow volumes and the volumes in the ensuing August-through-December period. This correlation is shown on Figure 2.

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<sup>4</sup> The monthly output of thermal units was discounted by their forced outage rates.



The model was run in its full stochastic mode, i.e., multiple games with water conditions, temperatures and, therefore, loads, and forced outages on thermal units determined randomly. In addition, a limited amount of imports was assumed to be available during off-peak periods.

## Results

### ***Stage 1 -- March through August 2001***

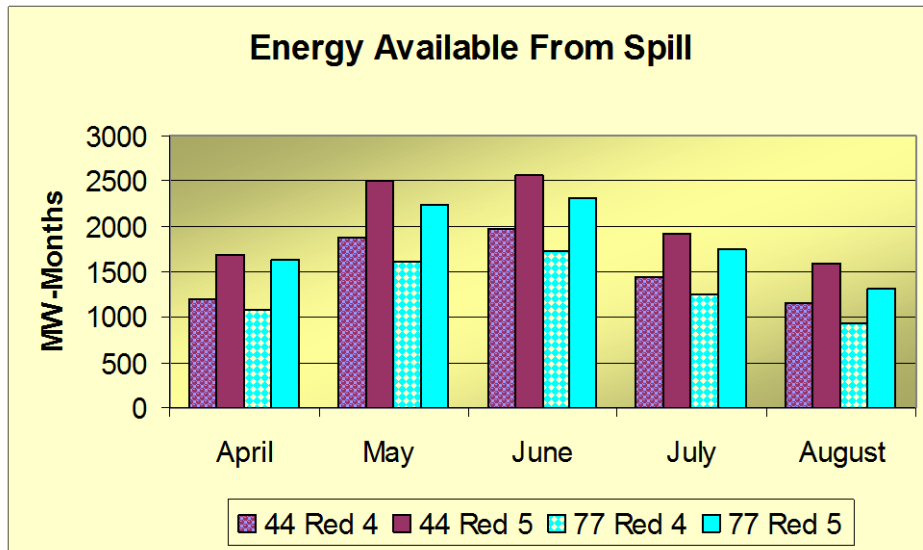
Operation of the system for the March-through-August period was analyzed for several different scenarios for 1944 and 1977 water conditions. For each year, a "Base Case" was run that corresponds to operation of the system according to the BiOp. In addition, a "Maximum Emergency Hydro" case was run that maintains spill and drafts reservoirs as necessary to meet load, using up to 10,000 megawatt-months of emergency hydro. Finally, three different spill reduction cases were run with a limited amount of emergency hydro (up to 1,000 megawatt-months) used as necessary to meet load while at the same time maintaining end-of-August reservoir contents very close to BiOp elevations (within 1 or 2 percent).

The spill reduction cases were:

- Spill reduction 4 -- No spill at federal projects;
- Targeted spill -- Morning and evening spill at John Day and Bonneville, no spill at other projects, federal or non-federal;
- Spill reduction 5 -- No spill at any projects.

The amount of energy involved in spill is quite large. Figure 3 shows the availability of spill energy across the spill season for the spill reduction 4 and 5 cases.

Figure 3



"Red 4" = Spill reduction which eliminates spill at all federal projects  
 "Red 5"= No spill at any projects, federal and non-federal

### Summer Summary

For each of these cases several measures were evaluated:

- The total curtailment across the period;
- The cost of imports IF the curtailment could be offset by purchases, assuming a \$250/MW-hr price;
- The approximate amount of spill energy used;
- The August 31 system content below BiOp elevations; and
- The amount of "retained" energy. The retained energy is the amount of spill energy available over and above that needed to meet load and restore system contents to BiOp elevations at the end of August.

This information is summarized in Table 1. Also shown is a result from the second stage of the analysis: the probability of unserved demand at some level across the 2001-2002 winter months. This will be discussed in a later section.



<b>Table 1 -- Summary</b>						
<b>Alternatives</b>	<b>Summer</b>					<b>Winter</b>
	<b>Total Curtailment (mw-mo)</b>	<b>Cost of Imports* to Balance Loads (\$Millions)</b>	<b>Apprx Spill Energy Used (mw-mo)</b>	<b>Aug 31 Content Below BiOp (mw-mo)</b>	<b>"Retained" Energy (mw-mo)</b>	<b>Winter Season (Dec-Feb) Loss of Load Probability</b>
Base Case BiOp(1944)	5606	\$1,009	0	0	0	20%
Max Emerg (1944)	0	\$0	0	5872 (-20.7%)	0	39%
Lim Emerg+ Red 4 (1944)	177	\$32	5186	211 (-0.7%)	3422	20%
Lim Emerg + Target (1944)	0	\$0	5237	369 (-1.3%)	4349	20%
Lim Emerg + Red 5 (1944)	0	\$0	5567	39 (-0.1%)	5569	20%
Base Case BiOp(1977)	7993	\$1,439	0	0	0	20%
Max Emerg (1977)	1663	\$299	0	7976 (-27.9%)	0	45%
Lim Emerg + Red 4 (1977)	1289	\$232	6345	127 (-1.4%)	432	20%
Lim Emerg + Target (1977)	441	\$79	7401	72 (-0.3%)	789	20%
Lim Emerg + Red 5 (1977)	89	\$16	7486	402 (-0.4%)	1652	20%

"Max Emerg" = Maximum use of emergency hydro up to 10,000 mw-months -- drafting reservoirs below BiOp elevations

"Lim Emerg" = Limited use of emergency hydro up to 1,000 mw-months

"Red 4" = Spill reduction which eliminates spill at all federal projects

"Target"= Targeted spill reduction with morning and evening spill at Bonneville and John Day, no spill at other projects, federal and non federal

"Red 5"= No spill at any projects, federal and non-federal

\* Imports priced at an average of \$250 per megawatt-hour

Several things are readily apparent from Table 1. The first is that operating the system to the BiOp to spill and meet flow targets is not an option. To do so would leave very large unserved load (curtailments) with either 1944 or 1977 water. If it were possible to purchase imported energy to meet those deficits, the cost could easily exceed \$1 billion, and it is not at all clear that purchases of this magnitude would be available.

A second observation is that by using maximum emergency hydro – drafting the reservoirs deeper – while maintaining spill could, with 1944 water, avoid summer curtailments. With 1977 water, there would be some remaining curtailment, but of a magnitude that might be managed with additional load reduction and some purchases. However, in this instance the curtailment occurs in August when imports might be especially hard to acquire. In both cases, the August 31<sup>st</sup> reservoir content is well below BiOp elevations. This has implications for reliability later in the fall and winter, as indicated by the higher loss-of-load-probability in the last column of Table 1. This question is examined in Stage 2 of the analysis.

The final observation is that with the combination of significant reductions in spill and some use of emergency hydro, it is possible to effectively eliminate curtailment in the 1944 water case and return reservoirs to their BiOp elevations by the end of August. In addition, there is an appreciable amount of retained energy in the system. For 1977 water, the combination of significantly reduced spill and limited use of emergency hydro does not eliminate curtailments but reduces them to much more manageable levels while returning reservoirs to BiOp elevations. The curtailments largely occur in May and June, coinciding with the period during which most planned maintenance on thermal units is assumed to be occurring. If water conditions this year approach 1977 conditions, the region could need to look to further steps to avoid curtailment. As in the 1944 water case, there is some energy retained in the system, although much less. We have looked at additional scenarios that do not reduce spill quite as much and compensate by using additional emergency hydro. However, unless we are willing to accept August 31 reservoir contents that are well below BiOp, the amount of reduction in spill has to be significant.

This retained energy could be used to restore some spill, fill reservoirs somewhat higher at the end of the summer or to generate additional power.<sup>5</sup> If this retained energy were used to generate electricity it could generate additional revenue to offset high power prices. Alternatively, it might be exchanged with California on an X Megawatt-hours-for-one basis, with much of the returned energy coming the following winter when it could help address potential power supply problems. In either event, some of the benefit could be set aside to fund fish mitigation measures that might offset some or all of the effects of a one-time reduction in spill.

It should also be recognized that introducing the amount of additional energy associated with spill into the market will have the effect of reducing market prices. To analyze the potential effect, two short-term price studies were done using the AURORA™ model. One run used the hydro generation associated with full spill, the other used the hydro generation associated with no spill, both for 1944 water. The average market price differential between the two runs was \$56/megawatt-hour. This would reduce the revenues that Bonneville and other Northwest utilities might receive from reducing spill and selling additional energy. But purchasers of power on

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<sup>5</sup> The degree to which this water can be used to increase reservoir levels is limited because of limited inflows to reservoirs high in the system late in the summer.

markets throughout the West would benefit from lower prices.<sup>6</sup> If we assume that 10 percent of the electricity consumed during the April-through-August period is secured through short-term markets as opposed to long-term contracts, the value of this reduction in price would be \$1.2 billion.

### Spring and Summer Flows

Also of concern is the effect of the operational strategies on spring and summer flows. Figures 4 and 5 show the percent change in flows from the BiOp operation for spring and summer at McNary and Lower Granite for 1944 and 1977 water respectively.

Figure 4

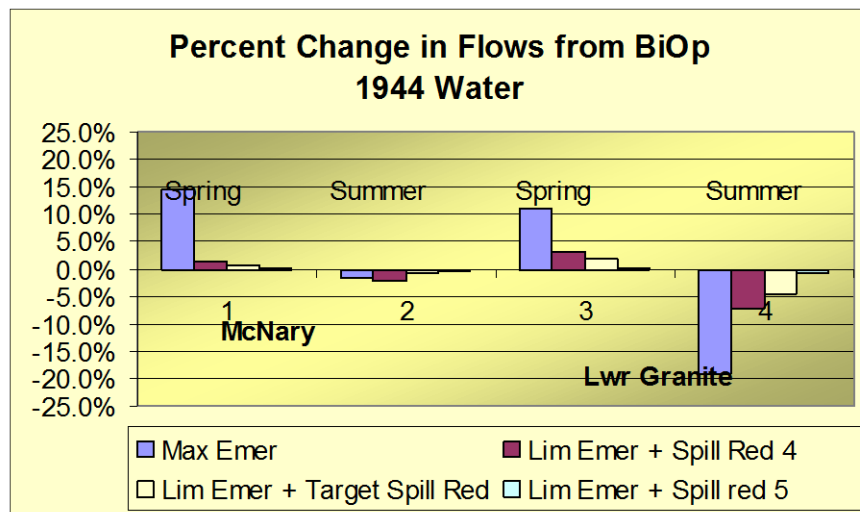
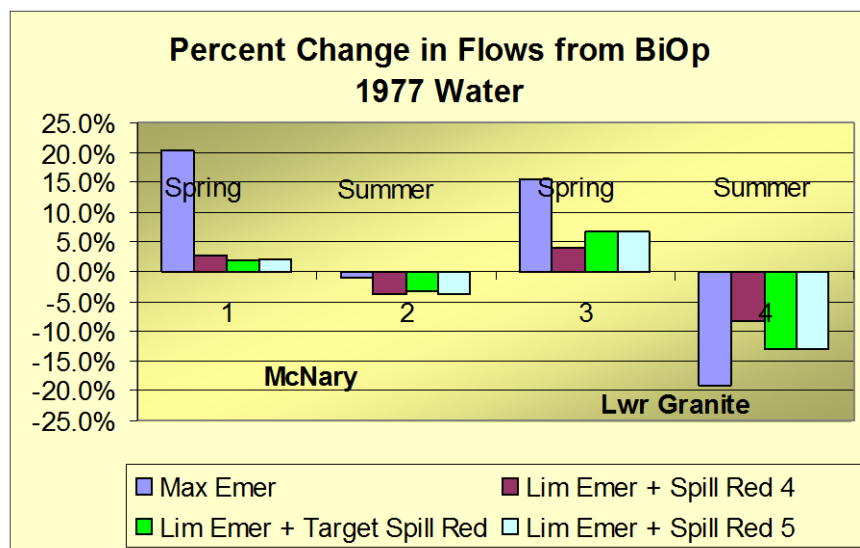


Figure 5



<sup>6</sup> Those like Bonneville who could have spill energy to sell would still have increased revenues, just not as great as current market prices might suggest.

Spring flows are generally increased from BiOp levels for the operating strategies modeled because each involves some emergency drafting. Summer is a different story. The system is trying to refill reservoirs that provided emergency energy earlier in the summer, thus reducing summer flows. This is particularly so for the “maximum emergency hydro” example. Generally, summer flows in the Snake are most at risk. In the reduced spill cases, some of the summer flows could be restored by generating with the retained spill energy or by spilling.

### ***Stage 2 -- September 2001 through February 2002***

This part of the analysis was focused on reliability concerns through the fall and coming winter. Of particular interest was to assess the effect of lower end-of-August reservoir elevations on the ability to meet load. Three cases were examined:

- Reservoirs at BiOp elevations at the end of August;
- Reservoirs starting at the elevations corresponding to the use of emergency hydro only for 1944 water conditions (79 percent of BiOp elevation); and,
- Reservoirs starting at the elevations corresponding to the use of emergency hydro only for 1977 water conditions (72 percent of BiOp elevation).

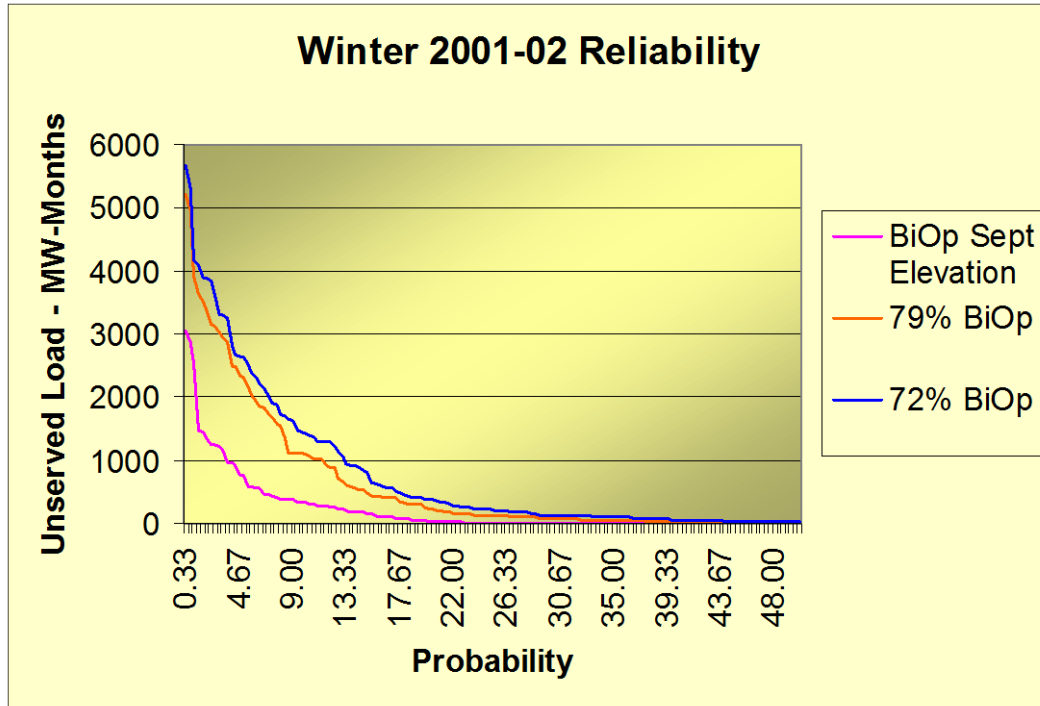
It should be pointed out that the last two cases are essentially surrogates for starting the reservoirs at elevations significantly below BiOp levels. For example, additional drafting for higher summer flows could have the same effect.

As noted earlier, this part of the analysis was carried out probabilistically using random draws of water conditions, forced outages of thermal units and temperatures which, in turn, are used to determine loads. A reduced set of water years was used to reflect the fact that there appears to be a weak correlation between the unregulated volumes in the fall and winter and the unregulated volumes in the preceding eight months. For this analysis, it was assumed that a very limited amount of imports was available beginning in October, primarily during off-peak periods. This reflects the experience of this past winter. We would hope that with additional generation scheduled to come online in the Southwest this summer, more imports might be available at an affordable price. Faced with curtailment, the simulation uses emergency hydro up to a total of 10,000 megawatt-months, limited by physical and operational constraints. In the absence of imports, the emergency hydro is restored to the extent possible by running in-region thermal units harder and purchasing imports.

### **Winter 2001-2002 Power System Adequacy**

The first question was the probability of curtailment occurring at some time during the winter season, the months of December 2001 and January and February 2002. This is shown in Figure 6.

Figure 6



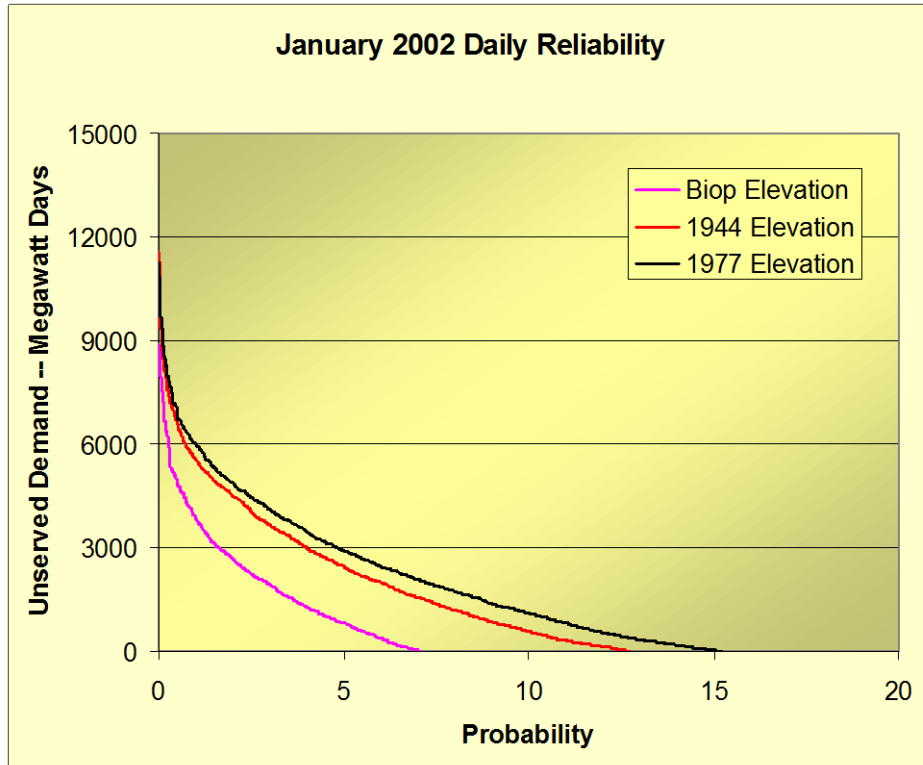
When starting at BiOp reservoir elevations, in 20 percent of the 300 winters modeled, there was some level of unserved load, with the maximum seasonal unserved load being over 3,000 Megawatt-months. This is not indicative of a reliable system and is consistent with the results of the Council's March 2000 study, which found a 24 percent probability of unserved load in 2003. In this year's analysis we have lower loads and some additional resources, both of which should improve reliability. However, this is counteracted by also having reduced import capability and lower average hydro capability because we are drawing from the lower two-thirds of the set of water years.

The amount of power needed to bring the loss of load probability down to 5 percent was found to be approximately 2,500 megawatts. This could be achieved through some combination of additional generation, imports, conservation and/or voluntary or purchased load reduction.

For the lower reservoir starting elevations, 39 to 45 percent of the winters experience some unserved load with average unserved loads of 800-900 Megawatt-Months in those winters and maximums reaching over 5000 Megawatt-months.

January is the worst of the winter months. To get a better sense of the magnitude of shortfalls that could be experienced, we looked at the average daily unserved load for that month. This is shown in Figure 7.

Figure 7



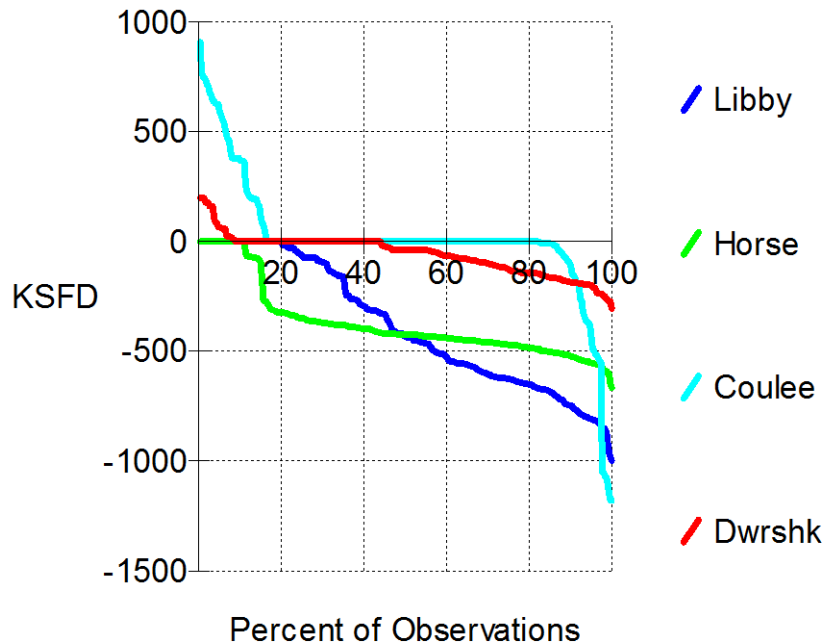
For the case with reservoirs starting at BiOp elevations, approximately 7 percent of the 9,300 January days simulated (300 games times 31 days), had some level of unserved load, with the maximum daily average reaching about 8,000 Megawatt-days. Starting the reservoirs at the lower elevations increases the percentage of days to 13 and 15 percent with the maximums reaching 10,000 to 11,000 Megawatts-days.

### Spring 2002 Reservoir Elevations

The other effect of lower reservoir starting elevations is on April 2002 reservoir elevations. These elevations are established to ensure being able to provide spring flows for downstream salmon and steelhead migrants. In the BiOp, approximately 12 MAF of water by April 15<sup>th</sup> is targeted for providing spring flows. On average, starting reservoirs in the fall at the lower elevations results in approximately 2 MAF less water in storage by April than when the reservoirs begin the fall at BiOp elevations. In the worst case with the lower starting reservoir elevations, April storage volumes are over 6 MAF lower. The duration curves of reservoir content (shown as difference from BiOp contents) is shown on Figure 8 for the case where reservoirs are started in September at their low 1977 water elevations.

Figure 8

## Difference in April 2002 Contents (1977 vs. BiOp)



### Conclusions

Several conclusions can be drawn from the results of this analysis.:

1. Operating the hydropower system to the BiOp targets for spill and flows would lead to either significant curtailments and/or very large purchased power costs this summer.
2. Operations this spring and summer that leave reservoirs at the end of August at elevations significantly below BiOp elevations expose the region to significantly increased probability of power supply adequacy problems next winter. In addition, such operations would result in a significant probability that April 2002 reservoir elevations will be well below BiOp elevations, thereby reducing spring flows for salmon.
3. The only alternatives we see that both avoid curtailments and/or large purchased power costs AND return reservoirs to BiOp elevations by the end of August involve substantial reduction in spill this spring and summer and limited drafting of reservoirs beyond BiOp elevations. Reductions in spill can be restored by purchases, reductions in load and additional generation. Alternatives that significantly reduce spill have the additional advantage of reducing market prices this summer and bringing additional income into the region, either in the form of dollars or returned energy next fall and winter.
4. Decisions need to be made now, but they can be revisited periodically as the spring and summer unfold. The spill season begins in April. By that time, we will have relatively little additional information about how the rest of the spring and summer are going to unfold. From the power

standpoint, a prudent approach would be to significantly reduce spring spill. If conditions improve through the spring, it may be possible to restore spill. If, instead, we were to opt to maintain spill or reduce it only slightly in the spring and conditions do not improve, that spill energy would be lost to the system and would necessitate more stringent and potentially very costly measures later on.

5. The potential for power supply problems this summer and next winter and the probable high cost of power call for continued and increased attention to implementing load reduction, conservation and new generation.

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