Power Supply Outlook
May 2001 – April 2002

Northwest Power Planning Council

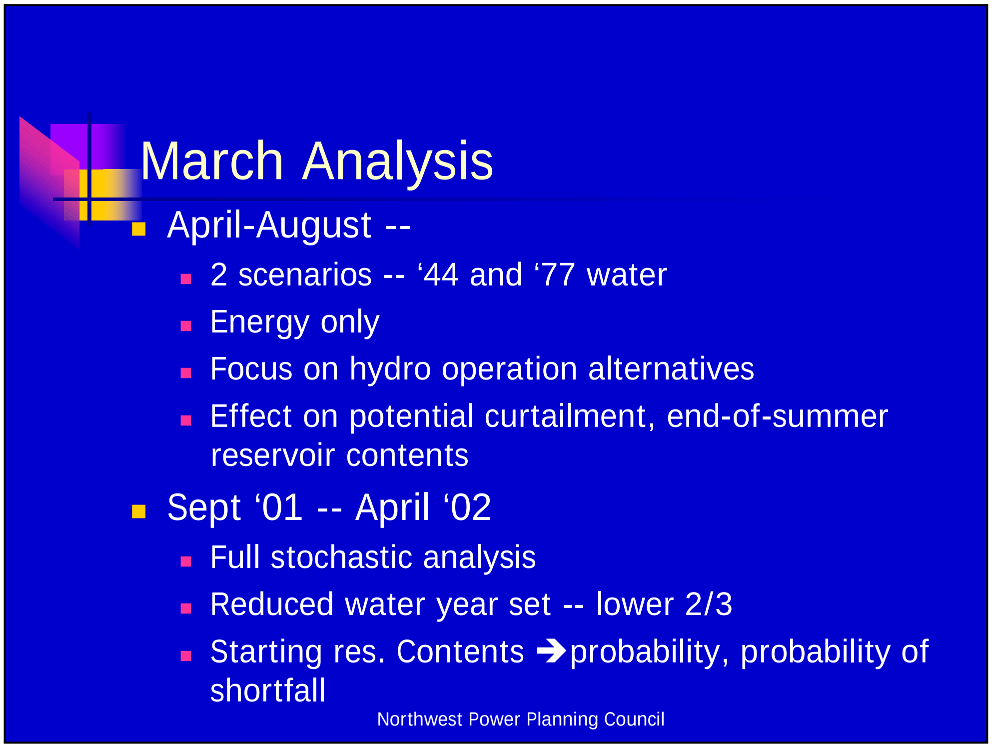
Council Briefing

May 30, 2001

This is the second of a series of periodic updates on the Northwest's power supply outlook. These updates are motivated by changes in the runoff forecast and other changes that could alter the load/resource balance.

The purpose of these updates is to provide the region's decision-makers with information that supports decisions that will result in:

- meeting the demand for electricity throughout the spring and summer;
- providing as reasonable as possible conditions for the migration of salmon, given the circumstances of a very poor water year;
- not worsening and, if possible, improving the reliability of Northwest power supply across the following winter and the ability to protect salmon in 2002; and
- Limiting the impact of wholesale power purchase costs on the region's consumers, the economy, and the financial condition of the region's utilities, including the Bonneville Power Administration.

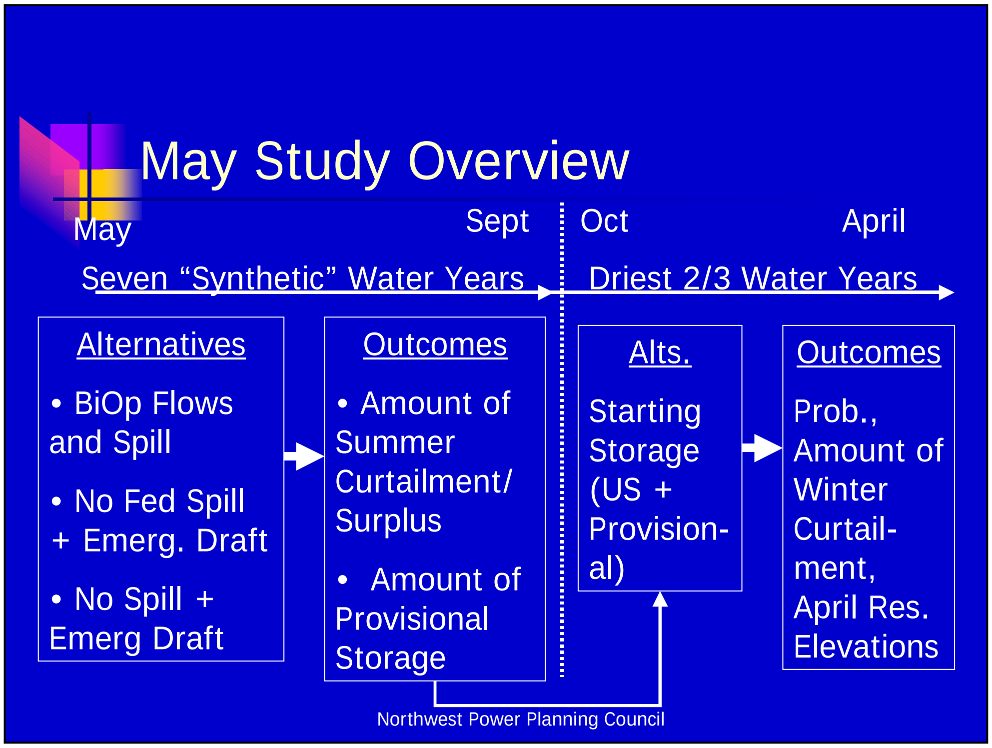


The previous analysis was carried out last March and released in early April. It was done in two stages. The Spring-Summer analysis focused on the April through August time frame. The analysis began with the March 1 reservoir contents and analyzed two basic scenarios corresponding to 1977 runoff 53.8 Million Acre Feet (MAF)) and 1944 runoff (60.2 MAF), the two lowest runoff years in the historical record. These years bracketed the then current runoff forecast of 57.6 MAF. It would have been preferable to be able to evaluate other runoff conditions both in terms of the overall volume and the shape of the runoff over the period of interest. However, data for synthetic water years at the level of detail necessary for the Council’s hydro regulation model was not available at the time.

The March analysis was limited to evaluation of monthly energy balances across the spring and summer since capacity problems are not anticipated to be a problem in the summer.

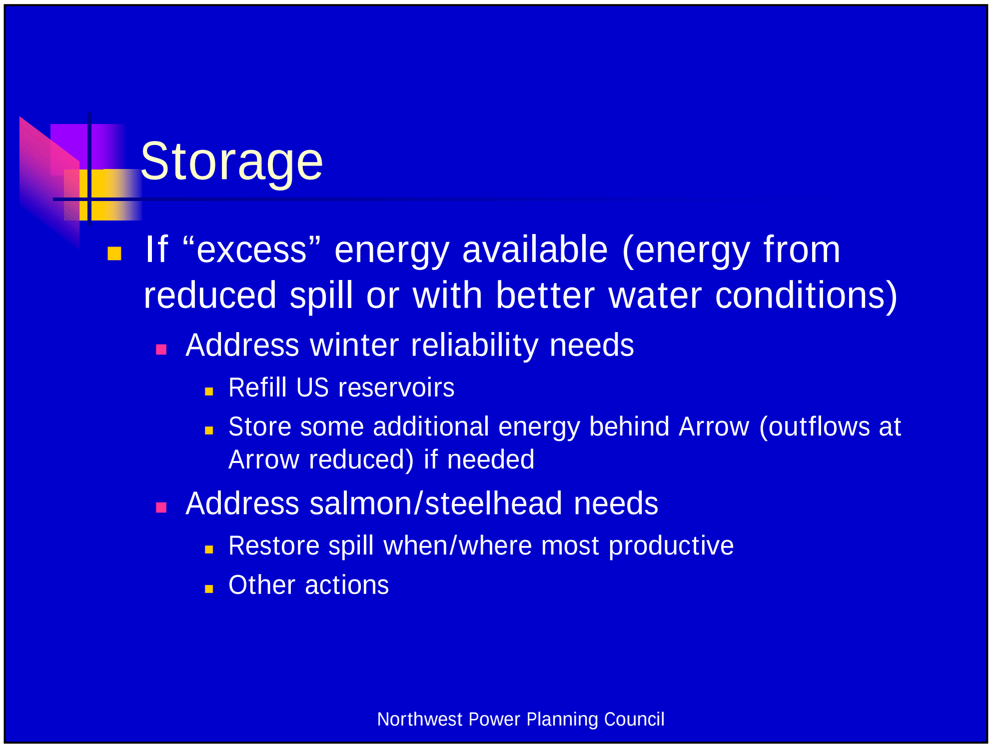
The focus of the analysis was on the effect of hydroelectric system operational alternatives and their effect on potential curtailment and end-of-summer reservoir contents. The latter are of importance because they can affect reliability during the subsequent fall and winter. The alternatives considered included running to the flow and spill requirements of the 2001 Biological Opinion; attempting to meet load by drafting reservoirs as deeply as necessary and various combinations of reduced spill and limited deeper drafts.

The fall-winter analysis was a full stochastic analysis where water conditions temperatures (and therefore, loads) and forced outages are sampled according to their probabilities in the course of several hundred simulations or “games.” This type of analysis allows assessment of the probabilities of reliability problems caused by combinations of poor water conditions, extreme temperatures, and forced outages on generating plants. Because there is a correlation, albeit weak, between the Jan-Jul runoff and the runoff over the ensuing fall and winter, only the lower 2/3 of the runoff years were used in the analysis. The primarily variable in the analysis was the starting content of the reservoirs in September. The analysis looked at the probability and magnitudes of shortfalls across the winter season (December, January, February and March) as well the April 15 reservoir contents. The latter are important to providing BiOp flows in the spring.



The May study was also carried out in two stages: May through September and October through April. This time, however, the data necessary for using synthetic water years was available. This makes possible a finer-grained assessment that incorporates the effects of not only the overall Jan-Jul runoff volume but also the effects of changes in the shape of the runoff across the months. The summer analysis was again an energy only monthly balance. The outcomes of interest were the amount of surplus or deficit and the resulting ability to store energy for the winter above the levels called for in the BiOp.

The winter analysis in the May study paralleled that in the March analysis in that it was a full stochastic analysis. The primary variable was the amount of energy in storage at the beginning of October over that associated with the US system reaching BiOp levels.



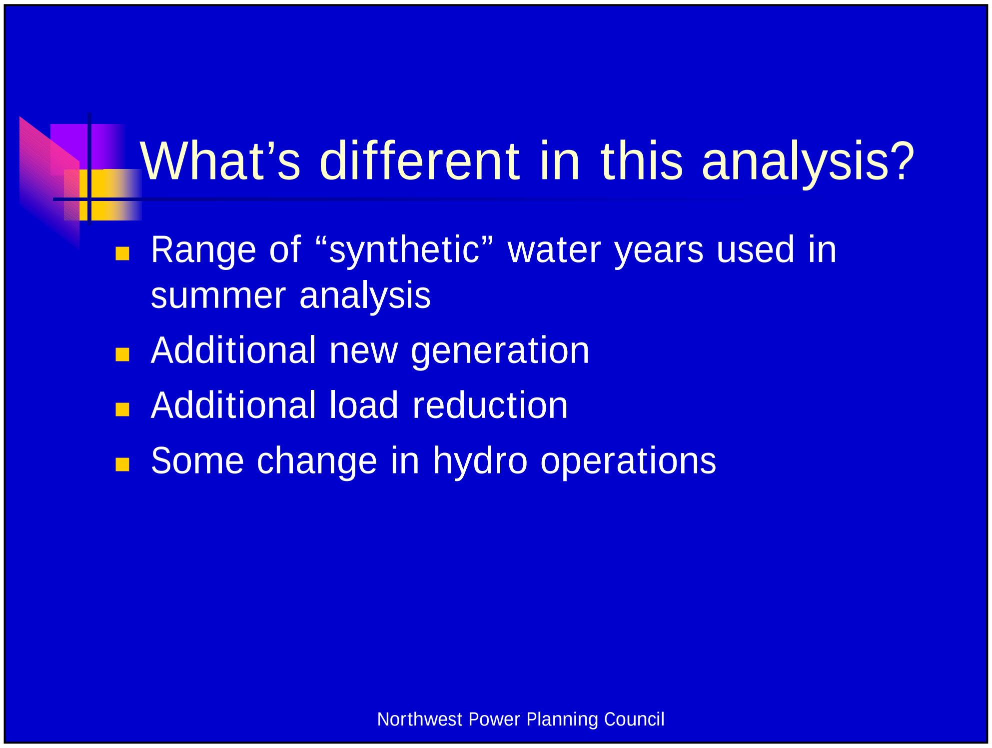
If there is energy available in excess of loads over the summer period, this energy could be used to address winter reliability problems and/or to address salmon and steelhead migration needs. This additional energy might result from one or more of the better water conditions evaluated, additional generation or load reduction or as a result of reduced spill.

For this analysis, we have looked first at how we might address winter reliability problems. Energy, when available, could be stored in a number of ways: filling US reservoirs above BiOp levels where possible; storing behind Arrow dam in British Columbia (reducing outflows at Arrow and making up the lost US generation with the excess energy); or exchanging energy with California with the return scheduled for next winter. For this analysis, we have modeled storage of energy behind Arrow.

Additional energy could be used to restore spill when and where it is most effective or some of the revenues that could be generated with the energy from reduced spill could be used to fund other salmon recovery measures. This analysis does not address how salmon might be best benefited by the excess energy.

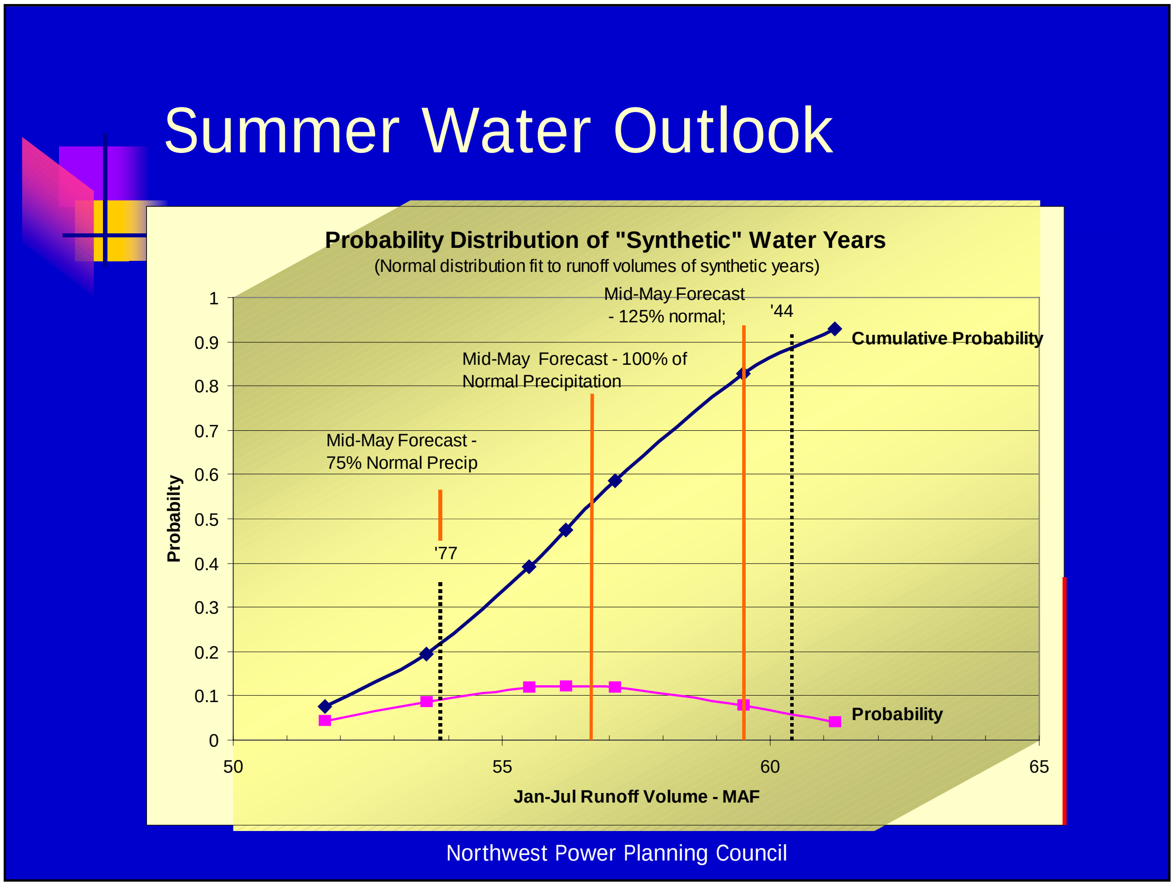
For the summer analysis, we have assumed that thermal generating units operated at their expected levels, i.e., their output has been discounted by their respective forced outage rates and scheduled maintenance periods. Average Northwest temperatures have been assumed which, in turn, results in average electricity loads for the region. Because of the forecast of tight supplies throughout the West, we have assumed that imports are not available beyond those under known firm long-term contracts. There are a number of plants in the region that are “merchant” plants. The output of these plants is not dedicated to Northwest loads and can go wherever it can earn the most. The same is true of power being re-marketed by Direct Service Industries. For this analysis, we have assumed that such power will be exported up to the limits of the intertie capacities during peak hours (over that required to meet long-term firm contractual obligations). These exports are shaped to reflect intertie loadings observed when the Southwest is experiencing high loads. This amounts to approximately 1/3 of the identified merchant plant output.

For the winter, we have assumed that off-peak imports will be available from the Southwest up to 4000 megawatts. Peak period imports are available up to 1000 megawatts at a high price such that this power is taken only as a last resort. This may be a conservative assumption given the new resources that are supposed to come on line in the SW this summer and fall. However, given last winter’s experience, we believe a conservative approach is appropriate. The winter analysis is again a full stochastic analysis with water conditions, temperatures and forced outages varying according to their probability. Again, the lower 2/3 of the water years were used. It was assumed that for the winter, full merchant plant output would be available to meet NW load.

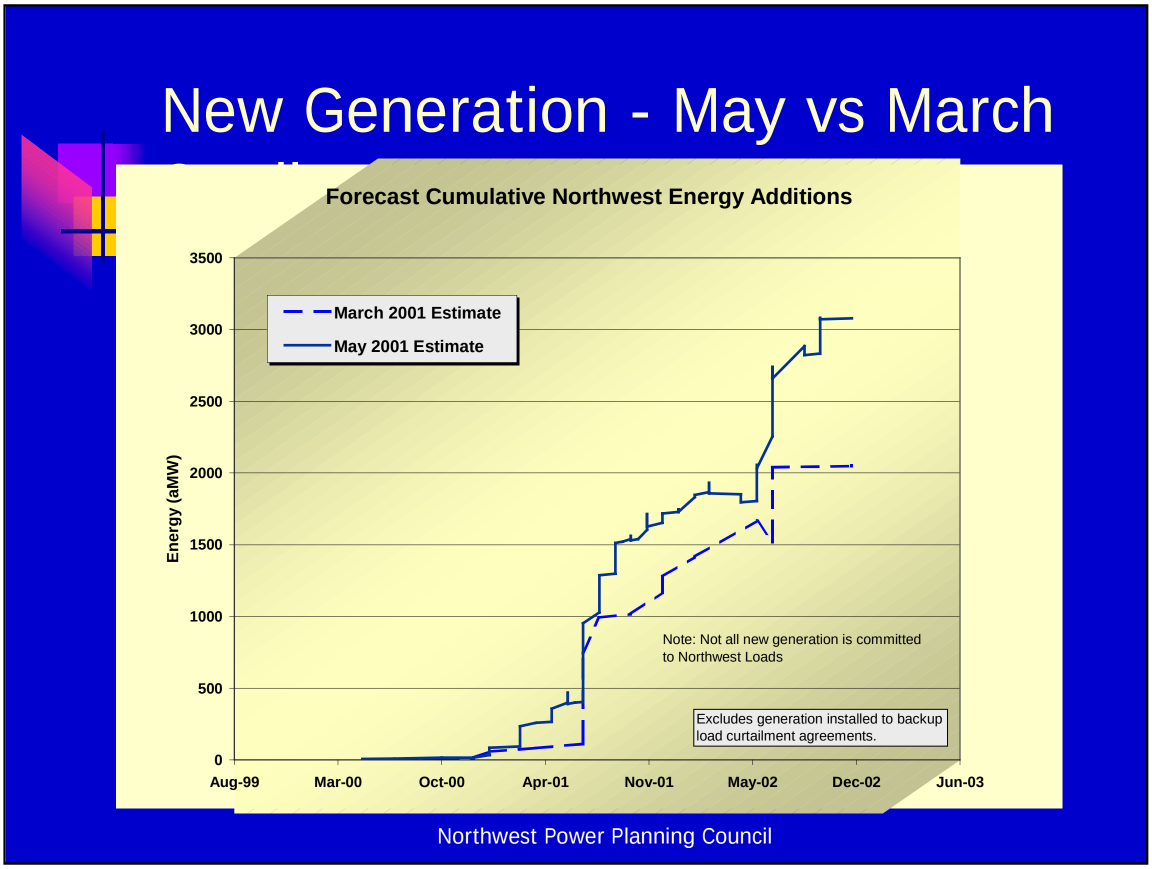


There are three primary differences in the current May analysis compared with the March analysis. First, there is the use of a range of synthetic water years. The second is additional new generation that has been identified since the March analysis. Third, there is additional load reduction. Finally, there are some minor hydro changes, primarily related to expected changes in operation of the Canadian reservoirs.

We have calibrated the Council’s model against Power Pool loads incorporating the load reductions identified for this analysis.

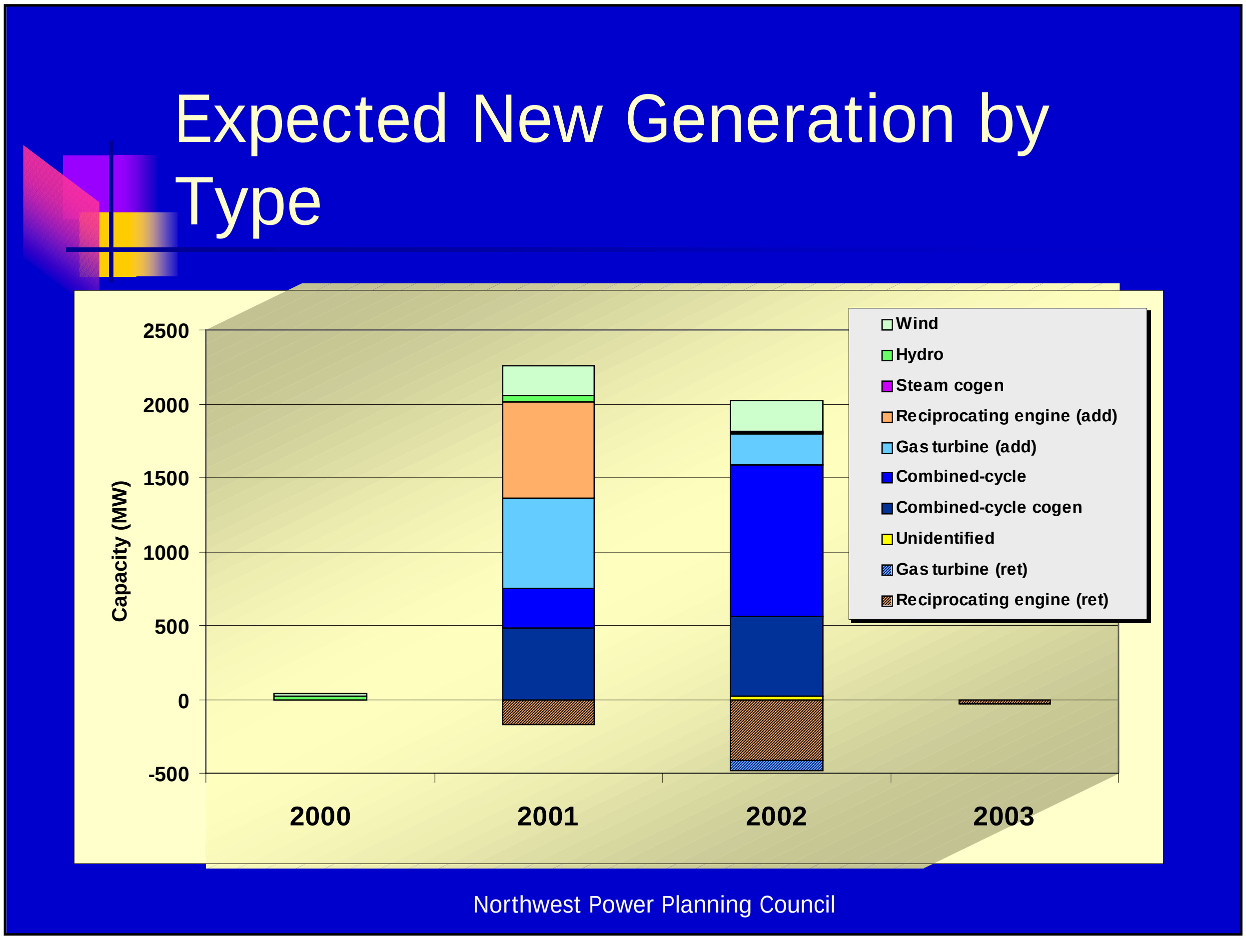


This figure illustrates the seven synthetic water years used in this analysis. The runoff volumes are shown on the horizontal axis while the standard and cumulative probabilities obtained by fitting a normal distribution to the points is shown on the vertical Axis. The mid-May forecast volumes are shown as solid vertical lines. These forecasts correspond to 75, 100 and 125 percent of normal precipitation from mid-May through the end of July. The mean of the runoff volumes for the 7 synthetic years is 56.4 MAF, 0.2 MAF less than the current runoff forecast. Also shown are the runoff volumes for 1977 and 1944. Bonneville generates the synthetic water years for their operational forecasting. They start with the current snow pack and then calculate runoff volumes for that snow pack and precipitation and temperatures for a set of historical years chosen to yield a distribution of runoff volumes that span the expected range and have plausible current month streamflows.

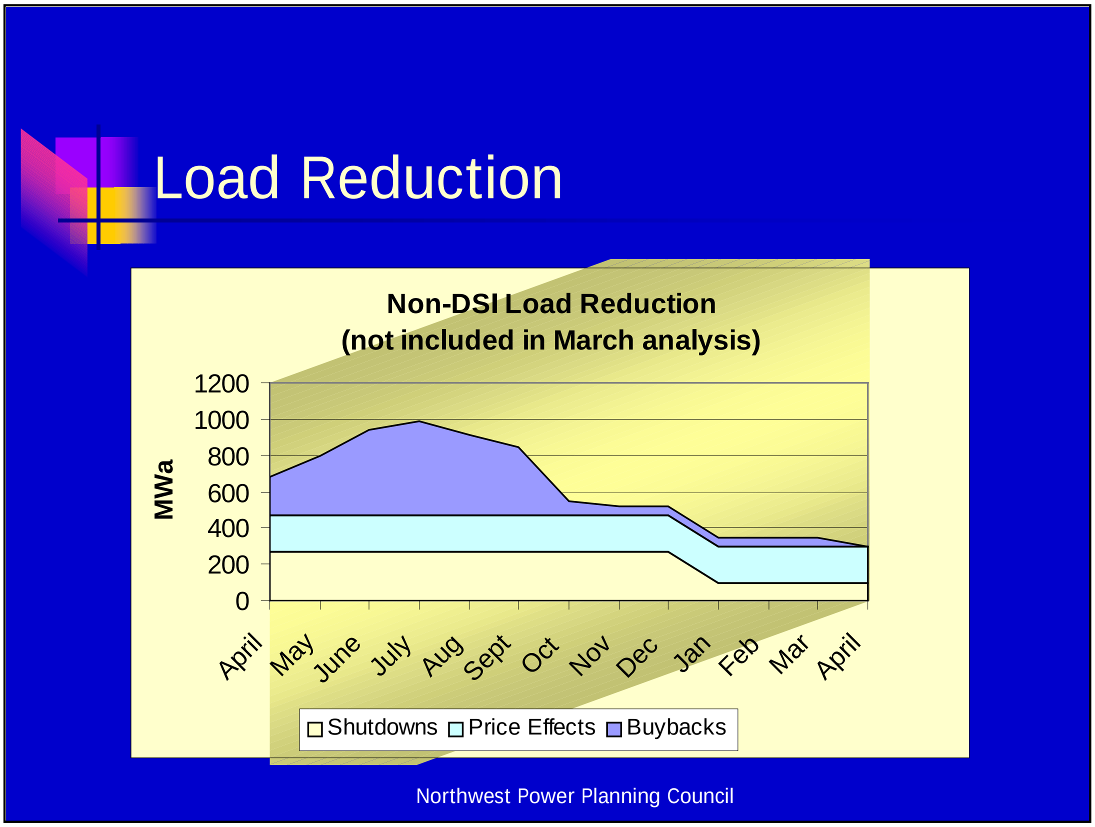


This chart shows the *expected* new generation used in the May analysis compared with that used in the March analysis. There has been a significant increase in the amount of new generation as a result of the initiation and acceleration of development of long-term resources as well as emergency generation brought on by utilities and others entities. These emergency generating units are typically small; single-cycle combustion turbines or internal combustion engines – frequently fueled with diesel.

There is some uncertainty associated with this generation. We have estimated the likelihood that new generation will come on line as scheduled based on the stage of development and the characteristics of the developer. Units that are under construction are given a 100 percent probability. Projects that are active and permitted are given a somewhat lower probability with subjective judgments regarding the strength of the developer. Active projects that are in the permitting process are given a lower probability, and so on.

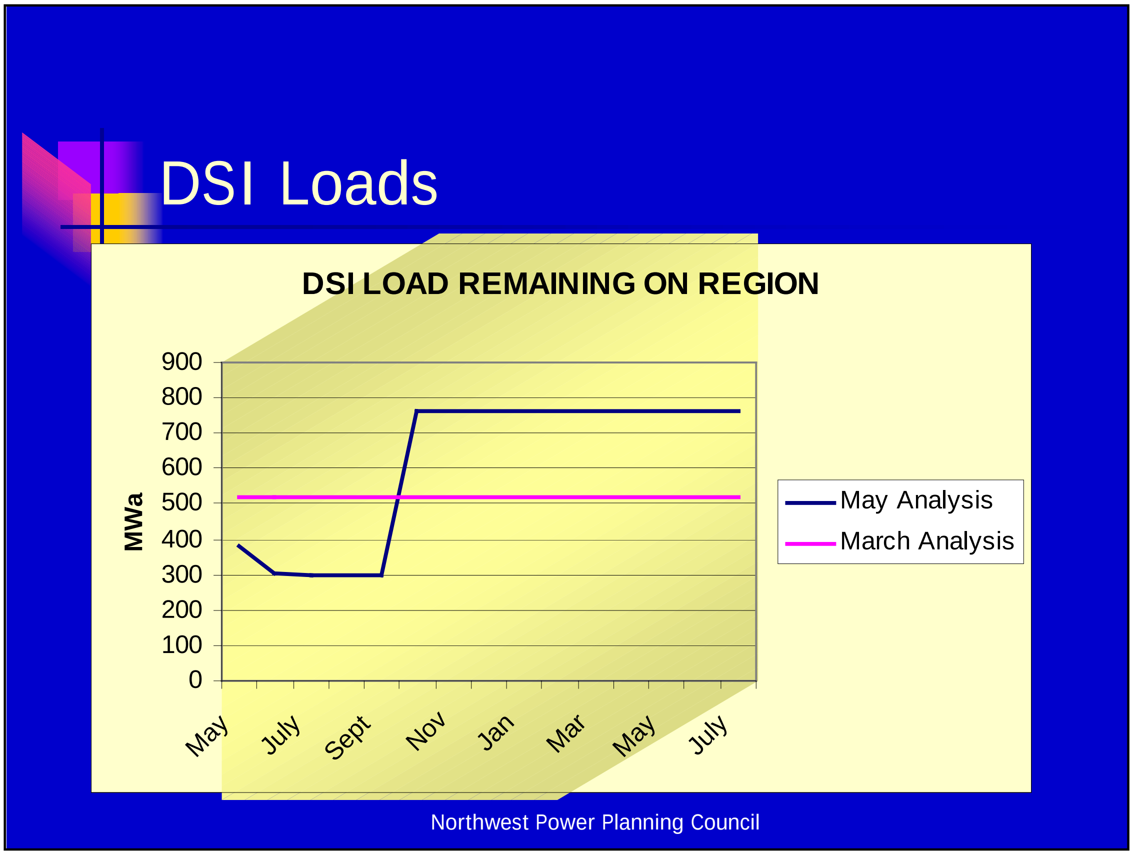


This chart shows the make-up of the new generation by type added by year. The shaded bars below the horizontal axis reflect retirements of generation largely as a result of expiration of environmental permits. This shows that there is expected to be approximately 700 MW of internal combustion generation and a similar quantity of simple cycle gas turbines in 2001. This is in addition to approximately 750 MW of combined cycle units (Klamath Falls Cogeneration and Rathdrum) and 200 MW of wind generation.

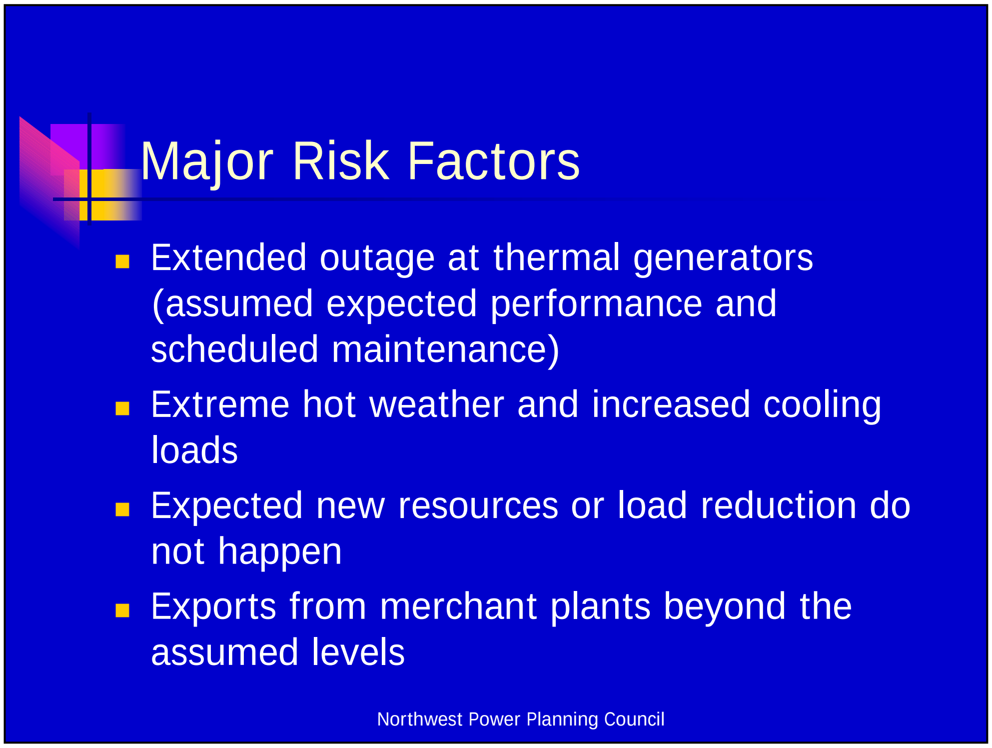


This chart shows the load reduction from sources other than the Direct Service Industries. This load reduction was not included in the March analysis. The bottom most area is load reduction brought about by industrial shutdowns in response to high power prices. This is shown as dropping off in 2002 although it could continue if prices do not moderate. The middle band is labeled price effects. It is the estimated load reduction (apart from shutdowns) experienced by several utilities who have had substantial rate increases. The top band is buybacks from industrial and agricultural customers. The summer "bulge" corresponds to load reduction in agricultural irrigation.

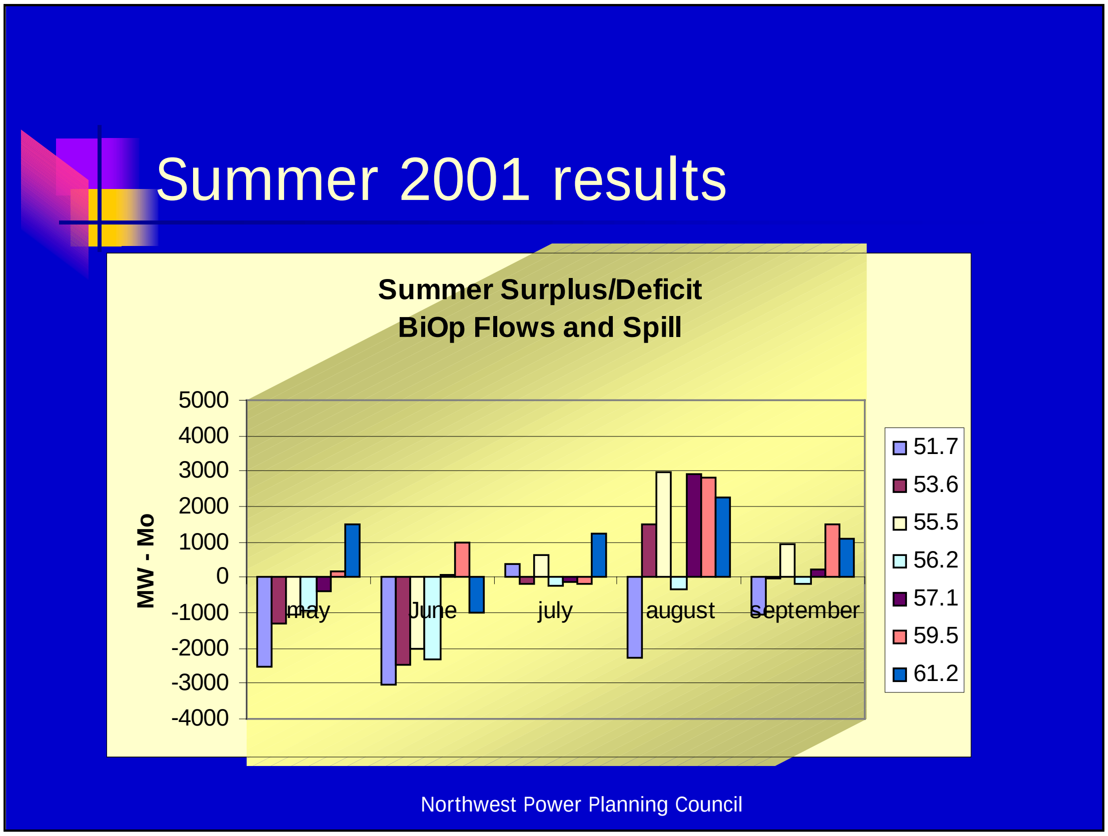
What is not included here is additional voluntary conservation or curtailment. Anecdotal evidence suggests that there has been a reasonable response to calls for conservation and reduction of unnecessary uses. We will try to more systematically evaluate this in the coming weeks.



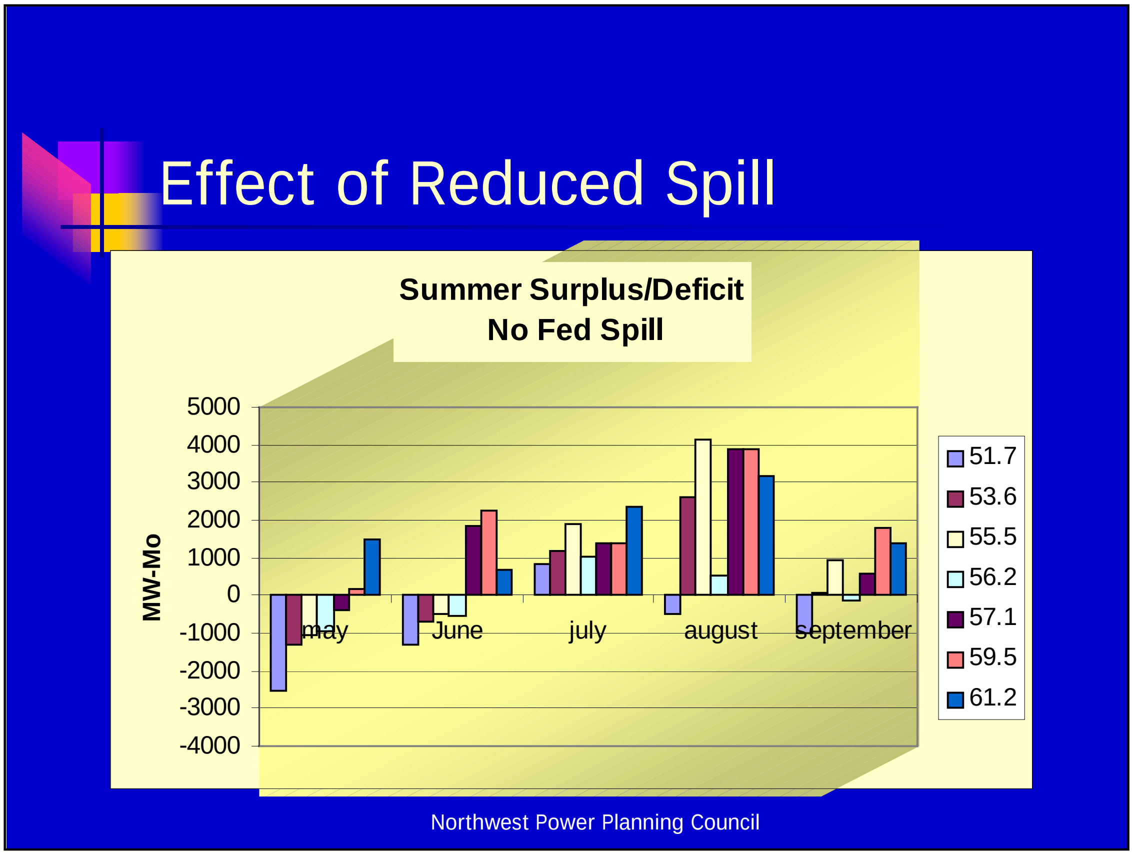
This shows the amount of Direct Service Industry load reflected in the March and May analyses. The March analysis had the DSI load at 520 megawatts throughout the summer and following winter. The May analysis reflects greater success by Bonneville at purchasing load reduction across the summer. However, when the new contracts come into place in October, there is the possibility that, depending on their individual circumstances, some DSIs might resume operation. Consequently, the May analysis incorporates the increase in load in October and throughout the following winter.



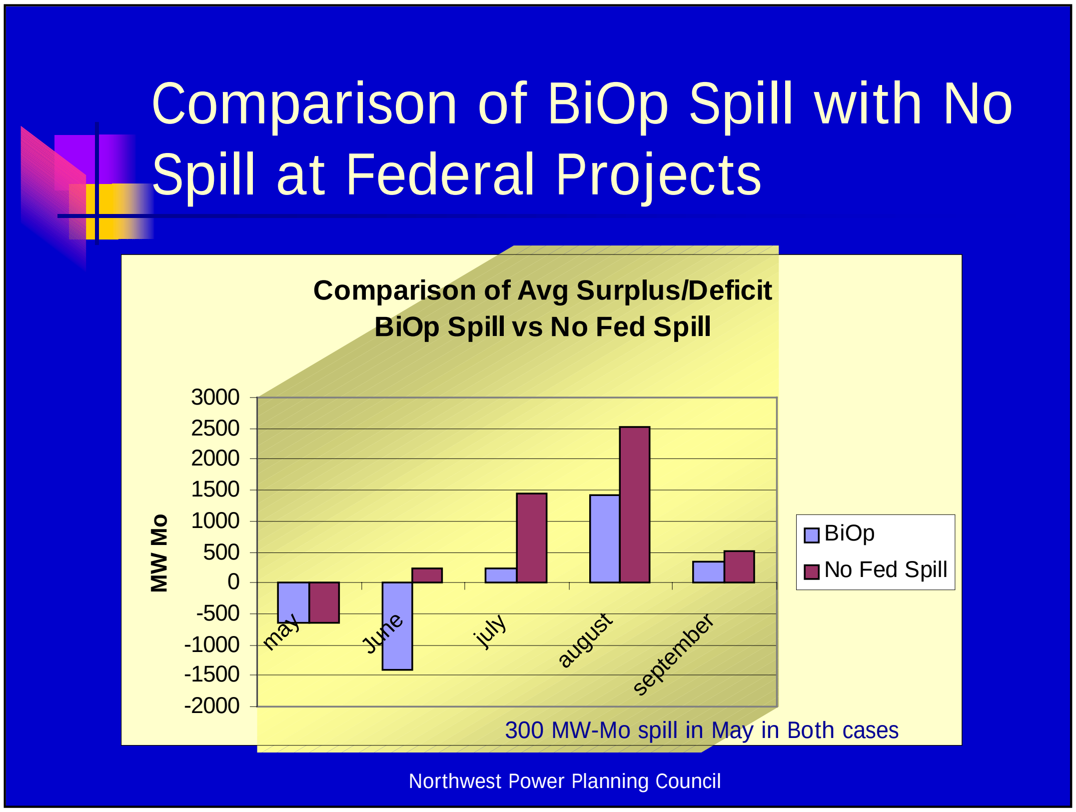
There are several risk factors that could worsen the outlook. This summer extended outages at major thermal generators, either as the result of unanticipated extensions of scheduled maintenance or greater than normal forced outages, could result in lower total generation. Extended hot weather could increase loads beyond those anticipated. Some of the anticipated new resources or load reduction might not occur as expected. Finally, merchant plants in the region might export at higher levels than assumed. While we based our estimates what it would take to fill the intertie during the peak hours, there is certainly room for additional exports in the shoulder hours. If prices in the Southwest are sufficiently higher than NW prices, additional power could go in that direction.



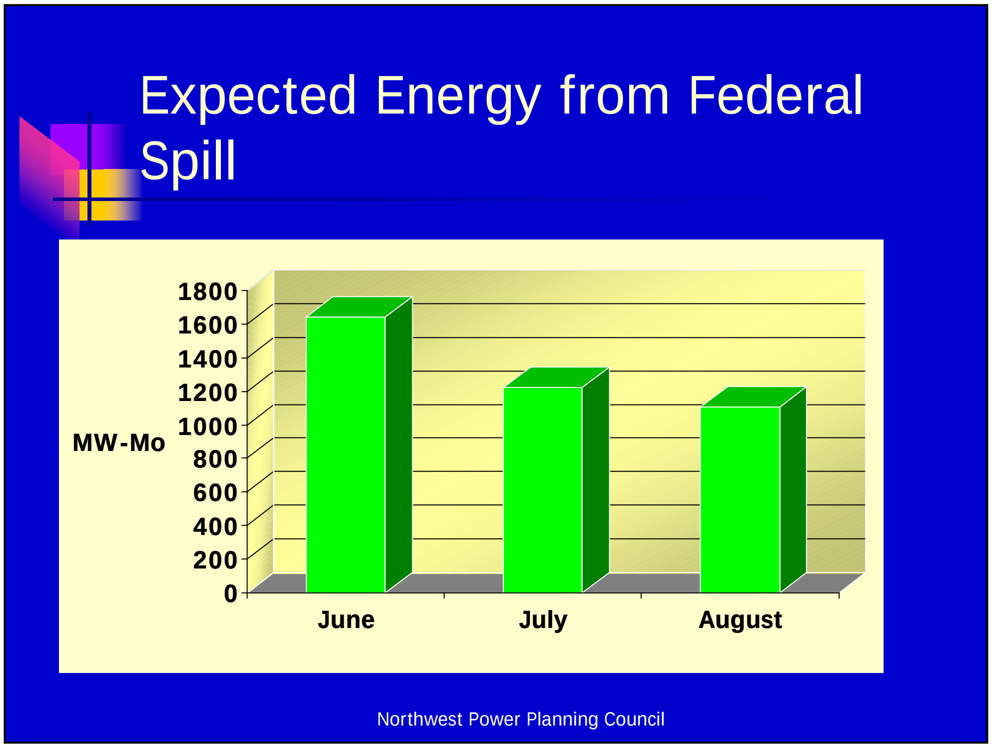
This figure shows the expected monthly surplus/deficit for the seven water years examined for the case of BiOp flows and spill in June through September and 300 Mw-Months of spill in May (compared to approximately 1700 MW-Mo for full May spill). The surplus/deficit figures were adjusted to ensure that the system reaches BiOp elevations by the end of September. The limited May spill reflects actual operations for May. Maintaining BiOp spill results in significant deficit in May and June for most of the water years examined. July is roughly in balance. August and September generally exhibit surpluses except for the driest of years. The pattern from month-to-month surplus and deficit for a given year illustrates the effect of the shape of the runoff. Years with quite similar January through July runoffs can exhibit significant differences from month to month.



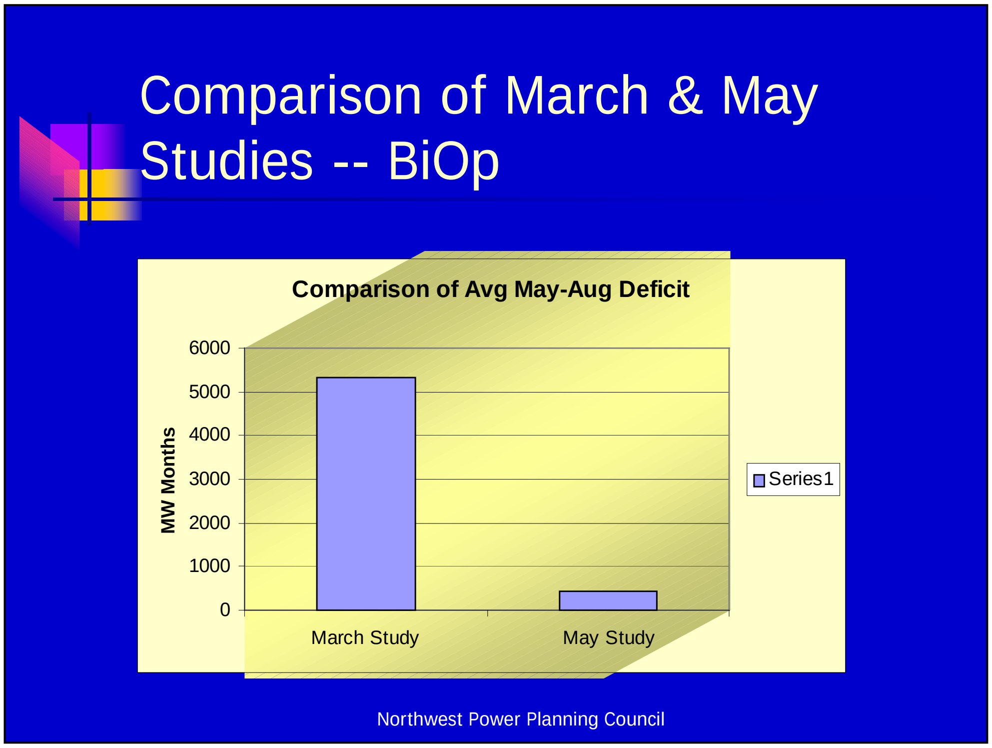
This figure illustrates the surplus/deficit situation for no spill at the Federal projects except for the 300 MW-months of May spill. As would be expected, the deficits are significantly reduced and the surpluses increased.



For ease in comparing the spill versus no spill at federal projects cases, this chart compares the average surplus/deficit by month for the seven synthetic water years for those two cases. The two cases are identical in May with each incorporating 300 MW-Mo of spill. Thereafter the effect of elimating spill is fairly significant.

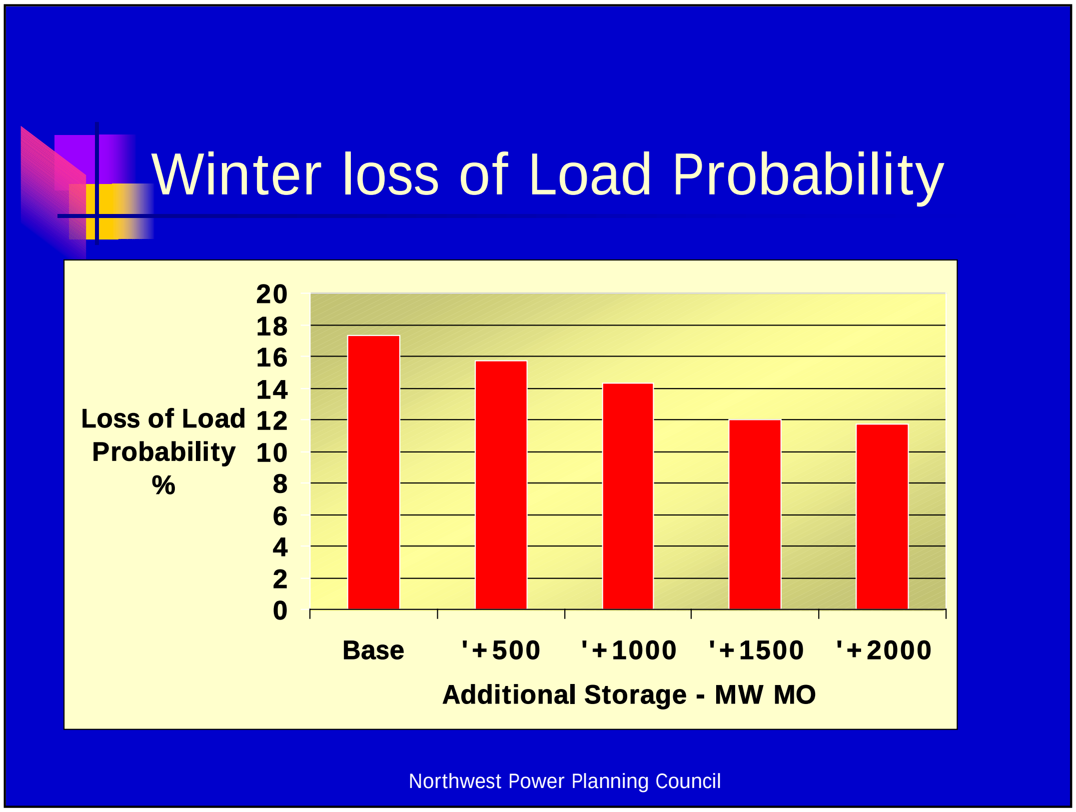


This figure illustrates the amount of energy associated with the spill at federal projects over the remaining spill months. If the market price of power averages $300/MW-Hour this summer, the value of this energy or, conversely, the cost of replacing it is approximately $854 million.



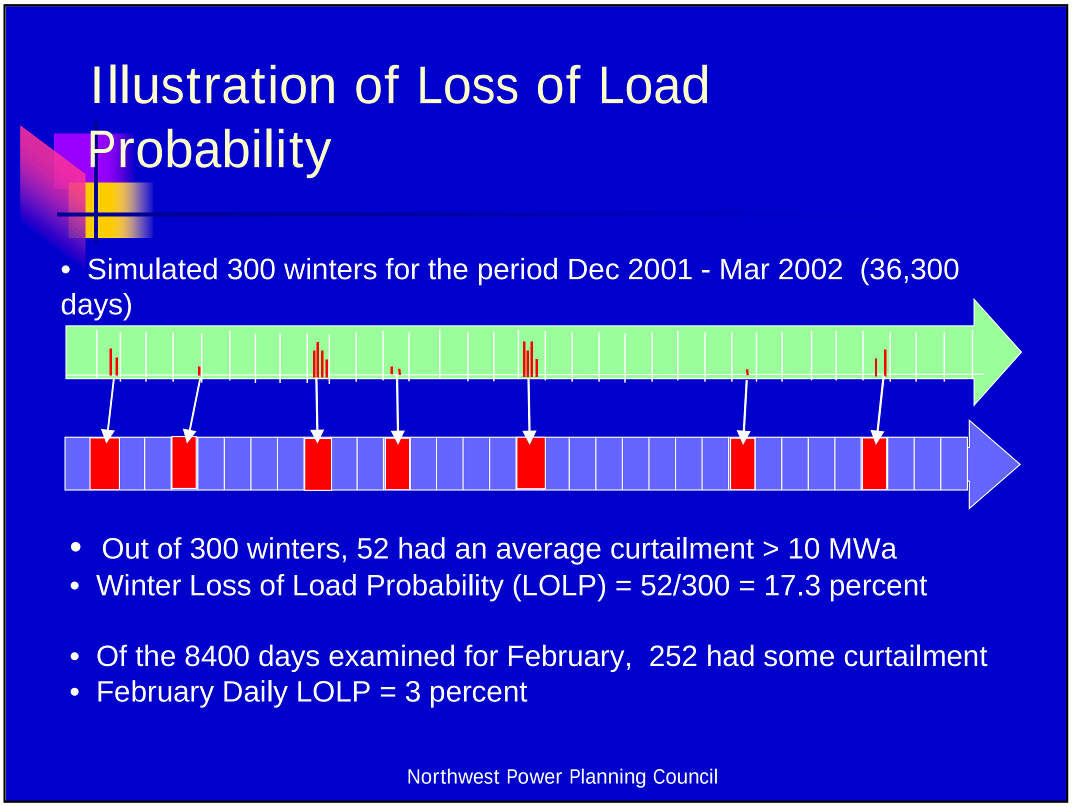
To illustrate the effect that the additional new generation and load reduction have on the supply situation, this chart shows the net average May though August deficits for the March and May studies and BiOp flows and spill (only 300 MW-Mo of May spill in the May study). March study deficit is the net monthly deficit for the average for ’77 and ’44 runoffs. The May study deficit is the net deficit for the May through August months for the BiOp spill case shown in the figure on page 16.

Between the March and May analyses we have seen approximately 5000 MW months reduction in average curtailment. About 3700 MW-Mo comes from load reduction and about 1800 from new resources. This is counteracted by about 400 MW-Mo loss in hydro production.



Looking to the winter months, we are primarily concerned about the probability that resources will not be sufficient to meet power needs. We were also interested in the effect of storing additional energy from the summer for winter use. This was modeled as storage behind Arrow dam in Canada by the beginning of October..

This chart illustrates the probability that resources will be insufficient to meet needs at some point across the winter months (December, January, February and March). The independent variable is the starting reservoir contents in October. The Base Case starts with reservoirs at the BiOp levels, approximately 10,000 MW-Months below full. The other cases add additional storage in Canada up to 2000 MW-Months. For the Base case the probability of shortfall is 17 percent. This is well above what is considered typical of a reliable system (5 percent). The additional storage reduces the likelihood of shortfall, although diminishing returns are apparent above approximately 1500 MW-Mo. This is because at this point, the remaining curtailments are largely capacity problems for which additional storage in Canadian reservoirs does little good. This situation could be improved by increased import capability beyond that assumed in this analysis and/or additional thermal generating capacity. It is possible that additional storage in some US reservoirs, e.g. Grand Coulee, might have a greater impact in addressing such problems. Outflow limits on the Canadian reservoirs limit how much they can contribute to addressing capacity problems.



The concept of loss of load probability is a difficult one. It is one way utilities historically have thought about generation reliability. LOLP is the probability that generation will be insufficient to meet demand at some point over some specific time window. We've defined the winter months, December to March, as the time window, and in 300 simulations, examined 36,300 days.

Any reliability event in any hour of a winter (regardless of size[1] or duration) causes a winter to be recorded as one in which load was lost. Whether there is one or 5 events in a winter are immaterial. Out of the 300 winters simulated, resources were insufficient to meet needs, including reserve requirements, one or more times in 52 of them, resulting in an LOLP for winter of 17.3 percent.

We also examined the daily loss of load probability in the worst month, February. Of the 8400 days examined, 252 or 3 percent had some curtailment.

[1] For these analyses, we have used a 10 MW threshold, below which we ignore shortfalls. Generally, a 10 MW shortfall should be easily manageable. However, if a winter-long average deficit of 10 MW were to occur in the span of 1 day, it would amount to a 1200 MW-Day shortfall.

February Daily Reliability

	Base Case (No additional Storage)	1500 MW-Mo Storage
Probability of Daily Shortfall	3%	1.4%
Average Magnitude - MW	1080	590

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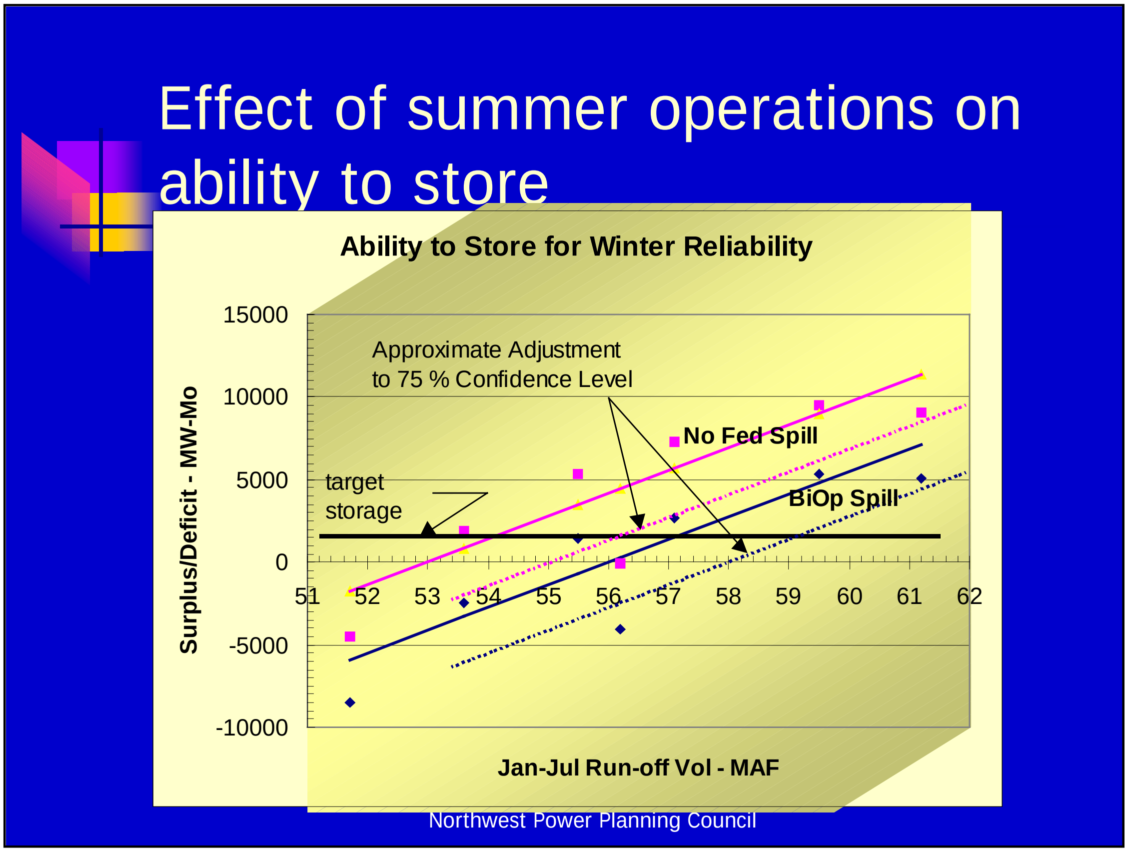
This chart illustrates the probability and average magnitude of daily reliability problems in February, generally the worst month. For the base case (BiOp reservoir levels at the beginning of October), 3 percent of the 8400 February days had a shortfall with the average being 1080 MW. Beginning October with 1500 MW-Mo of additional storage cuts the probability and magnitude of February shortfalls approximately in half.

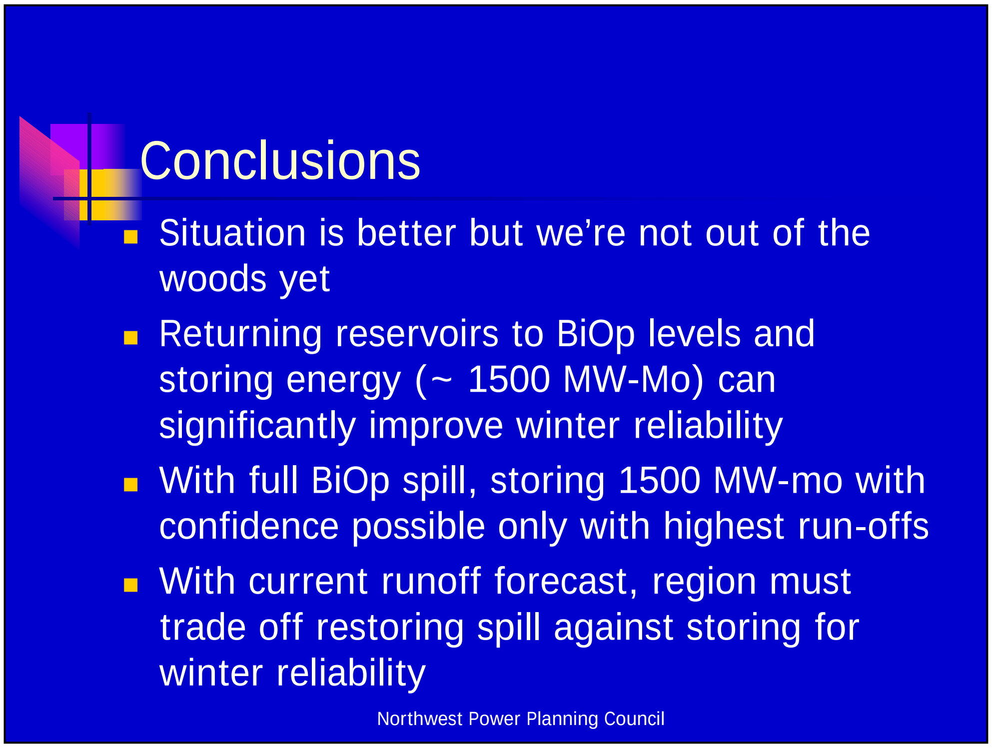


A primary purpose of this analysis is to inform decision makers on the operational decisions they will have to make this summer. The question of when and how much to spill is one of the most important. This analysis looked at two spill alternatives: full BiOp spill and no spill at federal projects. Both those alternatives incorporated 300 MW-Mo May spill at federal projects. FERC licensed projects were assumed to meet their full spill requirements in both alternatives.

The chart above is intended to illustrate the spill decision issue. The left and right solid lines are linear fits to the summer surplus or deficit values for the two spill alternatives corresponding to 6 of the 7 synthetic water years analyzed. The point at 56.2 MAF was omitted because we are not confident of its results. If we had absolute certainty about the runoff we are actually going to get, we could interpret this chart to say that with full BiOp spill, we can meet load as long as the runoff is above 56 MAF and we could store 1500 MW-Mo if the runoff is above 57.1 MAF. With the No federal spill alternative, the corresponding figures are 53 and 54.1 MAF.

Unfortunately, we are not certain about the runoff we will actually get. The dotted pink and blue lines are approximations to the 75 percent confidence level for the June runoff forecast. For the full BiOp spill case, if we want to be 75 percent confident that the actuall runoff will be sufficient to avoid curtailment (56 MAF or greater) we would need to have a June forecast level of 58 MAF. If we want to be 75 percent confident of sufficient runoff to be able to avoid summer curtailment and be able to store 1500 MW-Mo for next winter's reliability, we would need a June forecast of 59.2 MAF. For the no federal spill alternative, the 75 percent confidence numbers are 55 and 56.2 MAF respectively. The current runoff forecast is 56.4 MAF.

What this suggests is that the region is at or very close to the point where tradeoffs need to be made between summer spill and storage for winter reliability. Restoring very much spill could come at the expense of storage for winter reliability and vice versa.

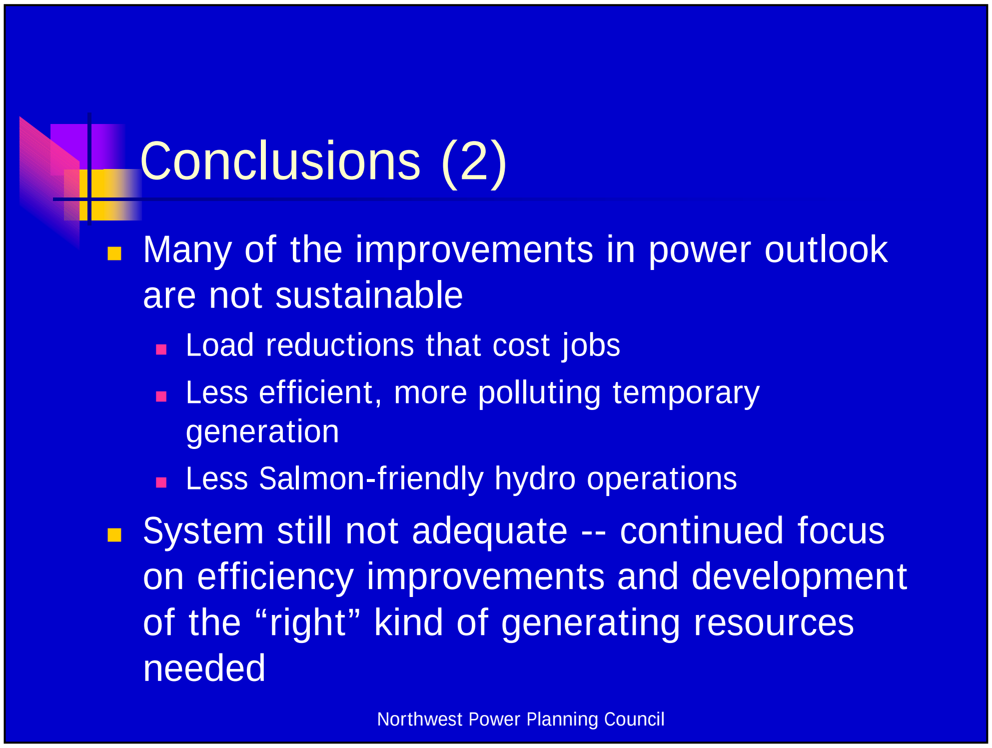


This analysis clearly demonstrates that the efforts of the region to conserve, to buyback power, to curtail loads, and develop more generation are bearing fruit. The situation has improved considerably since the March analysis. But there remain a number of risk factors that could cloud this picture. And, while improved, the winter reliability picture remains problematic.

This analysis also demonstrates that storing energy from this summer for reliability purposes next winter can have a significant positive effect. It may be that mechanisms other than that modeled in this analysis could have greater benefit, e.g. exchanges with California. However, we have not analyzed that or other alternaitves.

One of the ways by which the region has managed to meet loads thus far has been to dramatically reduce spill at the federal projects. Looking forward across the summer, restoring full BiOp spill would allow the region to meet loads and store for winter reliability with confidence only in the wettest water years modeled.

With the current runoff forecast, the region appears at or very near the point that it must make difficult tradeoffs between restoring spill and meeting energy storgage targets for winter reliability. As the confidence interval in the preceeding figure illustrates, there is still a sizeable degree of uncertainty in the runoff. As the summer progresses, that uncertainty will narrow. If runoff improves, we may be able to restore spill and meet reliability targets. If it does not, we may not be able to do both.



Finally, we must not lose sight of the fact that the power system is not adequate. Much of what has been done to improve the situation is acceptable in an emergency but is not acceptable as a long-term solution. Some people are not working because of the supply and price of power, we are experiencing greater levels of emissions of pollutants into the air, and we are causing some damage to salmon recovery efforts.

For the longer term, we need to keep a focus on improving the efficiency with which we use electricity and developing clean, efficient and affordable generation for the region.