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An Approximate Method to Assess the Peaking Capability of the NW Hydroelectric System

September 26, 2005

The best way to assess the hydroelectric system's peaking capability is to simulate its operation on an hour-to-hour basis under many different streamflow and demand possibilities. This is an ominous task and requires the use of sophisticated simulation software. The Bonneville Power Administration has such a computer model to assess the peaking capability of the federal hydropower system. This model simulates the operation of the major hydroelectric projects over a one-week (168 hour) period. It has its limitations but it is the best tool, to date, to assess this capability. Unfortunately, the model is too cumbersome and requires too much computer time for it to be incorporated into the GENESYS model.

To address this data requirement for GENESYS, a Trapezoidal Approximation methodology was developed to approximate the hydroelectric system's peaking capability. This method assumes a trapezoidal shape for daily demand, including a flat off-peak period, a ramp-up period, a flat on-peak period and a ramp-down period. The hydroelectric system is operated to match this trapezoidal load shape. A linear-programming technique is used to maximize the amount of on-peak hydroelectric generation while adhering to all operating constraints. This is done for various lengths of on-peak duration (2-hour, 4-hour and 10-hour peaks). This yields the approximate peaking capability of the hydroelectric system for various lengths of peak demand. This parameter is often referred to as the sustained peaking capability. As expected, the sustained peaking capability drops as the duration of on-peak hours grows. This is due to the limited amount of water available to sustain a particular output for longer and longer time periods. A more detailed description of the method is provided in Appendix A.

This methodology identifies the relationship between monthly hydroelectric energy generation and sustained peaking capability. Typically, as the energy generating capability of the system goes up, so does the sustained peaking capability -- but only so far. At some point, the sustained peaking capability flattens out regardless of the monthly energy production. Tables of these relationships are computed for every month and for different lengths of sustained peak (2-hour, 4-hour and 10-hour periods). These tables are used in GENESYS to approximate the hourly dispatch of hydro generation.

GENESYS simulates the operation of the hydroelectric system on a monthly basis. Once the monthly generation has been determined, the sustained peaking limits are obtained from the tables described above. As GENESYS simulates each hour's resource dispatch, the amount of hydro generation dispatched is limited by the sustained peaking capability. For example, hydro generation for a single hour cannot exceed the nameplate capacity of the projects. For any two-hour period, hydro generation cannot exceed the two-hour sustained peaking capability (as approximated by the method above). For any 4-hour period, hydro generation cannot exceed the 4-hour sustained peaking capability, and so fort.

In other words, the trapezoidal approximation tells GENESYS how much it can "stretch" the average monthly hydro generation into the peaks and valleys of the daily demand curve. As GENESYS simulates each hour's dispatch, it records any cases when demand could not be served or when the reserve margin could not be met. The types of events that GENESYS records vary from single hour problems to sustained periods of curtailment, that is, it captures both capacity and energy shortfalls. When a loss-of-load probability (LOLP) is calculated, it can capture both capacity and energy events.

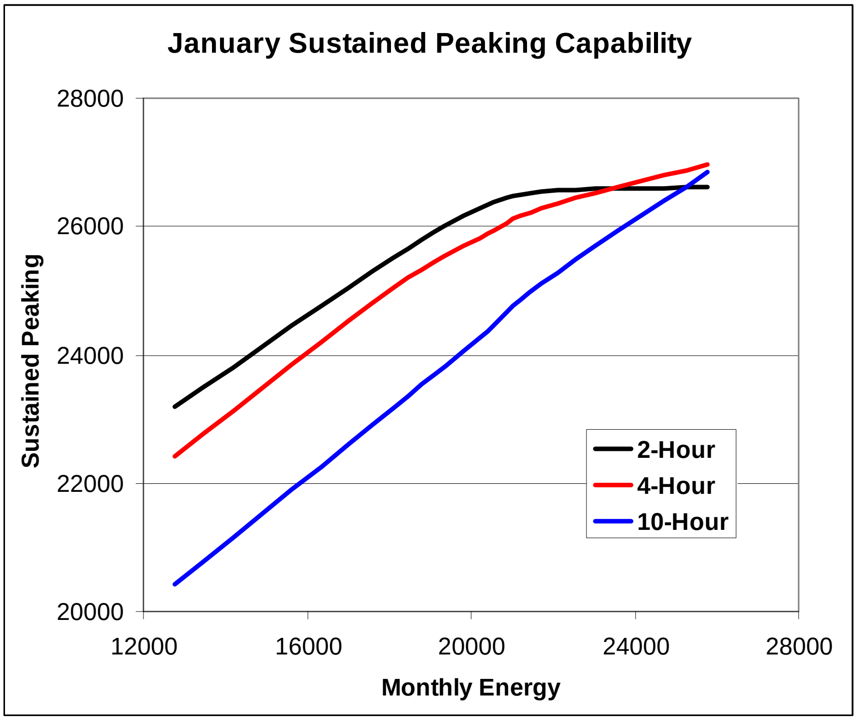

Figure 1

Figure 1 above illustrates the January sustained peaking capability as a function of average monthly energy production. As expected, the sustained peaking capability increases with increasing monthly energy at lower energy values, and then flattens out. Secondly, the sustained peaking capability drops as the length of the on-peak duration increases. For example, in Figure 1 above, a monthly energy production of 16,000 megawatt-months yields a 2-hour sustained peaking capability of about 24,500 megawatts, a 4-hour capability of about 24,000 megawatts and a 10-hour capability of about 22,000 megawatts.

As a means of verifying that this method is an appropriate approximation to use in GENESYS, sustained peaking values can be compared to analysis done by the Bonneville Power Administration. In its White Book (http://www.bpa.gov/power/pgp/whitebook/2003/), Bonneville defines sustained peaking capacity as that amount of capacity that can be delivered over 50 hours of peak demand per week (10 hours per day for 5 consecutive weekdays). This assessment assumes that energy delivered during peak load hours will be returned during light load hours. Adjustments are also made to capture changes in head (difference between reservoir and tail water elevations). The lowest sustained peaking capability usually occurs in February, when the combination of high load, low stream flow and potential for cold snaps make it the most critical month for the Pacific Northwest in the winter season.

The current White Book 10-hour regional sustained peaking capability for January is listed as 24,011 megawatts.[1] The energy level used to calculate this capability is not explicitly stated. The average energy production for January is about 16,400 average-megawatts (an estimate derived from the White Book). At that level of energy production, the 10-hour sustained peaking capability from Figure 1 above is about 22,250 megawatts -- a difference of about 1,750 megawatts or about 7 percent. However, at a monthly energy production of 20,000 megawatts, the peaking capability from Figure 1 is 24,000 megawatts, which matches the White Book value more closely. While this exercise shows that the trapezoidal approximation is “in the ballpark,” it is not a verification of the method. A better way to verify these results is to compare these sustained peaking capability values to results from Bonneville’s hourly simulation model.

[1] Bonneville staff have indicated to me that the White Book sustained peaking values may be out of date.

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APPENDIX A

A TRAPEZOIDAL APPROXIMATION TO THE PACIFIC NORTHWEST HYDROSYSTEM'S EXTENDED HOURLY PEAKING CAPABILITY USING LINEAR PROGRAMMING

Overview
The trapezoidal approximation is a linear programming based estimate of the Pacific Northwest's (PNW) hydroelectric system peaking capability. By approximating the Pacific Northwest's twin peak load shape to be that of a trapezoid, linear programming can be used to approximate the extended hourly peaking capability of the system. This approximation is useful for production cost and unit operation studies.

Why a trapezoid?

One basic assumption underlies the trapezoidal approximation to the sustained peaking capability of the Pacific Northwest (PNW) hydro system. We assume the Pacific Northwest load is sufficiently trapezoidal in shape that the capacity capability of the hydro system can be ascertained by finding the hydro systems ability to meet a trapezoidal shape. By trapezoidal we mean a flat on peak period and a flat off-peak period connected by two equal duration ramping periods. There is an implicit assumption that the deviations of the load about the trapezoid are within the capabilities of the hydro system. There is also an implicit assumption that the various constraints put on changes in hourly and daily output can be reasonably approximated by one ramp rate constraint.

It is recognized that the trapezoidal approximation is not an adequate model to assess capacity reliability, but it seems a reasonable approximation for finding the influence of capacity on production costs. The Bonneville Power Administration compared the results of the trapezoidal approximation to two of their hourly models and found consistent results.

Accounting for all the projects

There is not general agreement on what projects need to be included in an hourly model of the capability of the Northwest hydro system. The differences center on projects on smaller river systems, which represent about 2% of the peaking capability and have a mixed record of responding to regional peak loads. The projects explicitly modeled in the trapezoidal approximation are shown in Appendix A2. For the purpose of the following discussion the rest of the projects fall into two categories:

1) Projects that are modeled explicitly in the regulator but are not modeled explicitly in the trapezoidal approximation,
2) Projects not modeled explicitly in either the regulator or the trapezoidal approximation, the so called “hydro independents”.

Appendix A3 contains the description of both the relationship between plants and the physical parameters of the plants explicitly modeled in the Trapezoidal Approximation.

Assumptions of the Trapezoidal Formulation

Many assumptions were made to keep the problem tractable and yet have an adequate approximation. The assumptions are noted and described below.

1) When solving for peaking capability, the Trapezoidal Approximation acknowledges two basic types of projects; the reservoir and the pondage project. Reservoirs have sufficient hourly regulating capability that the diurnal shape of upstream releases can be ignored. This does not preclude the project from having to meet any other restrictions; it just removes the requirement to account for inflow shape and reservoir size. The working definition of a reservoir will be a project whose usable storage exceeds 500,000 acre-feet or 250,000 second-foot-days. Another definition might be framed in terms of storage relative to average monthly inflow. This would recognize that reservoirs can be smaller on lower flow river sections. Pondage projects are those projects, which have a limited amount of regulating capability, thud requiring the tracking of inflows and usable pond.

Some reservoirs have elevation and therefore h/k, which are determined solely by the month. Others have elevations and h/ks which are a function of system content, month, and water year. These differences in the behavior of h/k and elevation are made academic because the h/k used in the trapezoidal approximation is the one implied by the monthly regulator.

2) The various constraints placed on changes in hourly and daily outflow can be reasonably approximated by one ramp rate constraint measured in kcfs/hr.

3) The monthly average hk is an acceptable approximation to the hourly hk for production costing studies.

4) The release from reservoirs has a weekday/weekend shape with the weekday release (outflow) being 106% of the week (month) average.

5) If the time delay from an upstream plant to a pondage plant is greater than eight (8) hours then the upstream release is assumed to arrive flat. That is, the arriving flows loose the hourly shape but not the weekend/weekday flow shaping.

6) When calculating the peaking capability of the hydrosystem, the linear program assumes each weekday to be identical. It should be noted that weekends are not addressed explicitly. By constraining weekday operations, it is assured that the required weekend operation of refilling and meeting minimum flow will be feasible; that is, restrictions on a project's operation during the week assure that its weekend requirements can be met.

Consequences of using Regulator Input

1) The regulator provides the generation of the hydro independents and the generation of those PNW plants, which are not included in the trapezoidal approximation. In either case, for projects not explicitly modeled in the trapezoidal approximation LP the energy from these plants is

totaled and 50% of the energy is assumed to be delivered flat with the other 50% being delivered in the shape of regional load. For a ten-hour peak, with the analysis based on 1973 through 1988 regional loads, the ratio of ten-hour peak to average energy production was **1.087**.

2) Project constraints expressed as weekly averages or weekly allowable ranges are met, on average, in the monthly regulation. Thus, as long as the study concerns capacity available under "ordinary" conditions, these constraints can be ignored.

3) The regulator provides the average monthly release from the reservoirs.

4) The month average h/k is obtained from the regulator by dividing the month average megawatts by the month average of (outflow - spill).

Generator Forced Outages and Maintenance

The data for modeling maintenance is based on the 1992, 1993, and 1994 'Green Book'. The NWPP provided the megawatts on maintenance, monthly, for each of these three years. For each month the average maintenance during the two lowest (highest) maintenance weeks was calculated. These two numbers, expressed as a percent of the total capacity are used as an equi-probable distribution of the capacity out for maintenance.

The average forced outage rate (FOR) of hydro generation units in the PNW is 2.44%, per a conversation with the Corp of Engineers about their NERC submittal. With the large number of units, 278, and the large span in unit sizes, 6.67 mw to 870 mw, a good approximation of the distribution of units on outage is available from the normal approximation to the binomial distribution of the average unit size and failure rate. The trapezoidal approximation accounts for unit forced outages using the following algorithm:

1) Calculate the installed capacity (IC),
2) Find the average (capacity weighted) FOR (AFOR),
3) Approximate the outage distribution by the Normal distribution with parameters:
E(out) = IC*(1. - Percent Capacity on Maintenance)*AFOR, and
V(out) = E(out)*(1. - AFOR), derived from the binomial approximation,
4) Calculate the 75th percentile and the 25th percentile.

This procedure results in a four state equi-probable approximation of hydro forced outage and maintenance. The four states can be visualized as:

High Maintenance and High Forced Outages
High Maintenance and Low Forced Outages
Low Maintenance and High Forced Outages
Low Maintenance and Low Forced Outages

Parameters used in the Trapezoidal Approximation Linear Program

1) Project Variables

T_{on} = average turbine flow during on-peak period (kcfs)
T_{off} = average turbine flow during off-peak period (kcfs)
S_{on} = average spill during on-peak period (kcfs)
S_{off} = average spill during off-peak period (kcfs)
S_0 = storage at beginning of the off-peak period (kcfs-hrs)
S_1 = storage at beginning of ramp up period (kcfs-hrs)
S_2 = storage at end of ramp down period (kcfs-hrs)

2) Project Constants (most vary by month)

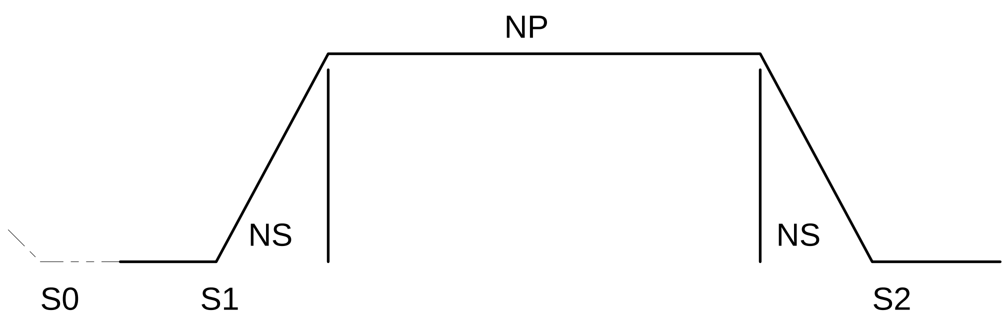
Q_{min} = minimum instantaneous total flow (kcfs)
Q_{max} = maximum instantaneous total flow (kcfs)
T_{max} = maximum instantaneous turbine flow (kcfs)
S_{min} = minimum instantaneous spill (kcfs)
Q_{avg} = average flows from ISAAC or SAM (kcfs)
* RR = ramp rate limit (kcfs/HR)

NOTE: RR should be set as the most restrictive, or maybe most representative, of the limits imposed by either forebay change, tail water change, or flow change.

* PS = maximum usable storage (kcfs-hrs)
SF = average side flows from ISAAC or SAM (kcfs)
HK = production coefficient (mw/kcfs)

***constant over all months**

3) Load Variables



NP = number of peak hours
NS = number of shoulder hours
NOFF = number of off peak hours

NOTE: NP + 2*NS + NOFF = 24

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NOTE: See Appendix A4 for the description of other time variables used in the formulation.

Linear Programming Formulation

1) Objective Function

Maximize the on-peak generation while minimizing spill. That is:

max $\sum HK*T_{on}$ - 100 * $\sum (S_{on} + S_{off})$.

NOTE: Including -100 * $\sum (S_{on} + S_{off})$ in the objective function serves two purposes. It forces the linear program to drive spills at the individual projects toward the minimum requirement. Also, because 100 is much greater than any h/k, it prevents spilling at upstream plant(s) to benefit the peaking capability of downstream plant(s).

2) Constraints on Reservoirs in the Linear Program

a) Minimum instantaneous total flow constraints

$T_{on} + S_{on} \Rightarrow Q_{min}$ (kcfs)

$T_{off} + S_{off} \Rightarrow Q_{min}$ (kcfs)

b) Maximum instantaneous total flow constraints

$T_{on} + S_{on} <= Q_{max}$ (kcfs)

$T_{off} + S_{off} <= Q_{max}$ (kcfs)

c) Maximum instantaneous turbine flow constraints

$T_{on} <= T_{max}$ (kcfs)

$T_{off} <= T_{max}$ (kcfs)

NOTE: Appendix A3 contains a table of h/k versus full gate flows for all the plants. Since the regulator provides the h/k for the period being studied, the Trapezoidal Approximation can calculate the full gate flow Q_{max} . Thus this constraint accounts for both the installed capacity and the forebay elevation.

d) Minimum instantaneous spill constraints

$S_{on} \Rightarrow S_{min}$ (kcfs)

$S_{off} \Rightarrow S_{min}$ (kcfs)

e) Ramp rate constraint

$T_{on} + S_{on} <= T_{off} + S_{off} + NS*RR$ (kcfs)

f) Average flow released from project equals regulator release

$(T_{on}+S_{on})*(NP+NS) + (T_{off}+S_{off})*(NOFF+NS) = Q_{avg}*24 *1.06$ (kcfs-hrs)

NOTE: Unique to reservoirs is a constraint stating that the average flow released from a project must match the ISAAC or SAM dispatch. This constraint reads that what is released during the weekdays must equal 106% of the month average flow as given by ISAAC or SAM. The purpose of taking 106% of month average is to simulate the shifting of water from the weekend into the weekdays. The 106% figure comes from the observation that the loads for typical weekdays are usually 106% of the week average load.

3) Constraints on Pondage Projects in the Linear Program, Time Lag (T)
For a pondage project all but one of the reservoir constraints are still required. The exception is that the
f) Average flow released from project equals regulator release constraint is replaced by a set of constraints on the use of limited pondage. These other constraints are:

g) Storage constraint,

S_0 <= PS (kcfs-hrs)

S_1 <= PS (kcfs-hrs)

S_2 <= PS (kcfs-hrs)

h) Water balance equation,

NOTE: The water balance equations keep track of the arriving water, any shape it may have, and any effects due to time delay. Because of its complexity this constraint will be developed in three steps to motivate its form.

STEP 1: The basic premise driving the water balance equations is that the releases at a particular plant (Ton + Son and Tof + Sof) minus the releases of any upstream plants (Tup-on + Sup-on and Tup-of + Sup-of) must equal the side flows (SF) in both the on-peak and off-peak period. Using this basic premise, the water balance equations in their most simple form read as follows:

Noff*(Tof + Sof) - Noff*(Tup-of + Sup-of) = Noff*SF

N1*(Ton + Son) + NS*(Tof + Sof) - N1*(Tup-on + Sup-on)
- NS*(Tup-of + Sup-of) = (24 - Noff)*SF

STEP 2: As written, the above pair of water balance equations do not take into consideration the water stored in the pond nor the effects of delayed upstream inflows. If pondage is accounted for, the amount of water released during the off-peak period (Noff* (S1 - S0)) and the amount of water released during the on-peak period ((24 - Noff)* (S2 - S1) must be added to the equations.

S1 - S0 + Noff*(Tof + Sof) - Noff*(Tup-of + Sup-of) = Noff*SF

S2 - S1 + N1*(Ton + Son) + NS*(Tof + Sof) - N1*(Tup-on + Sup-on)
- NS*(Tup-of + Sup-of) = (24 - Noff)*SF

STEP 3: The above equations now account for storage, but do not consider delayed inflows. As written, the equations assume instantaneous arrival of inflows. In accounting for time delays, the proportion of the up-stream flows which arrive during a period other than their release (i.e. on-peak releases arriving during off-peak hours) must be included. The equations for calculating this flow (Tterm) can be found in the Appendix A4. Using the adjustments for the arrival of delayed upstream inflows, the water balance equations take the final form:

S1 - S0 +Noff*(Tof + Sof) - Tterm*(Tup-on + Sup-on)
+ (Tterm - Noff)*(Tup-off + Sup-off) = Noff*SF

S2 - S1 +N1*(Ton + Son) + NS*(Tof + Sof) + (Term - N1)*(Tup-on + Sup-on)
- (Tterm + NS)*(Tup-off + Sup-off) = (24 - Noff)*SF

i) Weekday draft constraint.

$S_2 - S_0 <= (PS - (S_1 - S_0))/5$ (kcfs-hrs)

$S_2 - S_0 <= (PS - (S_0 - S_1))/5$ (kcfs-hrs)

NOTE: This constraint requires that the total **daily** drawdown (refill) can be no more than one fifth (1/5) of the maximum **weekly** drawdown (refill).

j) Weekend minimum flow , weekend refill constraint

When drafting daily, it becomes necessary at certain pondage projects to track whether the project will be able to meet its weekend minimum flow and refill requirements. To insure that the project is capable of meeting its weekend requirements, one weeks worth of releases from the up stream plant (168*Qup-out) plus one weeks worth of side flows (168*SF), less what was released from the upstream plant during the five weekdays (70*Ton and 70*Son, 50*Tof and 50*Sof) plus weekday side flows (120*SF), must be enough water to meet the weekend minimum flow (48*Qmin) less what was drafted during the five weekdays (5*S2 - 5*S0). The weekend minimum flow equation is as follows:

168*(Qup-out + SF) - 70*(Tup-on + Sup-on) - 50*(Tup-of + Sup-of) -120*(SF)
>= 48*Qmin + 5*(S2 - S0)

Appendix A2

Forced Outages and Maintenance

The file FOR.DAT contains two sections. The first section gives for each project:

- the number of installed units,
- the total megawatts installed, and
- the forced outage rate.

When significantly different capacity units are installed at the same project then units of the same size are collected separately. Noxon (NOXON) and Boundary (BOUND) are examples.

The second section of this file is the maintenance outage distribution. Maintenance is given by period and measured in percent of the installed capacity. There are two maintenance levels for each week. They represent respectively a average low maintenance week and an average high maintenance week.

First Section of FOR.DAT

PROJECT	UNITS	MW	FOR
H HORS	4	421.00	2.44
KERR	3	160.00	2.44
THOM F	6	40.00	2.44
NOXON 1	1	24.00	2.44
NOXON 2	4	430.00	2.44
CAB G	4	230.00	2.44
ALBENI	3	50.00	2.44
BOX C	4	80.00	2.44
BOUND 1	4	660.00	2.44
BOUND 2	2	420.00	2.44
LIBBY	5	600.00	2.44
COULEE 1	18	1929.00	2.44
COULEE 2	3	2070.00	2.44
COULEE 3	3	2415.00	2.44
CH JOE 1	16	1413.00	2.44
CH JOE 1	11	1203.00	2.44
WELLS	10	890.00	2.44
CHELAN	2	54.00	2.44
R RECH 1	7	818.00	2.44
R RECH 2	4	528.00	2.44
ROCK I 1	10	212.00	2.44
ROCK I 2	8	410.00	2.44
WANAP	10	956.00	2.44
PRIEST	10	907.00	2.44
BRNLEE 1	1	225.00	2.44
BRNLEE 2	4	450.00	2.44

OXBOW	4	220.00	2.44
HELL C	3	150.00	2.44
DWRSHK 1	2	207.00	2.44
DWRSHK 2	1	253.00	2.44
LR.GRN	6	932.00	2.44
L GOOS	6	932.00	2.44
LR MON	6	930.00	2.44
ICE H 1	3	310.50	2.44
ICE H 2	3	382.50	2.44
MCNARY	14	1127.00	2.44
J DAY	18	2795.00	2.44
RND B	3	300.00	2.44
PELTON	3	120.00	2.44
DALLES 1	14	1260.00	2.44
DALLES 2	8	792.00	2.44
BONN	18	1186.00	2.44
SWFT 1	3	268.00	2.44
SWFT 2	2	76.00	2.44
YALE	2	133.00	2.44
MERWIN	3	150.00	2.44

Second Section of FOR.DAT

PER	MAINT(LOW)	MAINT(HIGH)
1	.078	.111
2	.088	.109
3	.055	.083
4	.028	.048
5	.023	.027
6	.034	.044
7	.052	.063
8	.037	.081
9	.037	.081
10	.064	.080
11	.056	.069
12	.062	.088
13	.078	.108
14	.078	.108

Appendix A3
Definition of the Hydro System

The file SYSTEM.DEF contains two sections. The first section gives for each project:
- the immediate downstream project,
- a flag indicating whether this project is included in the study (1) or not(0),
- the time lag (hrs) to the downstream plant, not given for downstream reservoirs, - any ramp rate limit (kkcfs/hr), a (-1.) indicates no constraint,
- the storage available for daily fluctuation, (-1.0) indicates a reservoir,
- the installed capacity (mw).

The second section of this file is a linear interpolation table for full gate flow versus HK. Projects that have the HK entry 0 are assumed to have constant full gate flow as shown.

First Section of SYSTEM.DEF

Project	Downstr	Inc	Lag	RR	Pond	Cap
H HORS	KERR	1		-1.	-1.0	421
KERR	THOM F	1	31.	-1.	-1.0	160
THOM F	NOXON	1	.5	-1.	181.0	40
NOXON	CAB G	1	.5	-1.	155.1	554
CAB G	ALBENI	1		-1.	517.5	230
ALBENI	BOX C	1	1.	0.	-1.0	50
BOX C	BOUND	1	1.	-1.	84.0	230
BOUND	COULEE	1		-1.	337.5	1080
LIBBY	COULEE	1		-1.	-1.0	600
COULEE	CH JOE	1	3.	21.4	-1.0	6414
CH JOE	WELLS	1	2.	-1.	540.0	2616
WELLS	R RECH	1	5.	-1.	1186.0	890
CHELAN	R RECH	1	1.	-1.	-1.0	54
R RECH	ROCK I	1	1.	-1.	435.6	1346
ROCK I	WANAP	1	1.	-1.	133.2	622
WANAP	PRIEST	1	1.	-1.	1948.0	956
PRIEST	MCNARY	1	11.	-1.	537.6	907
BRNLEE	OXBOW	1	1.	-1.	-1.0	675
OXBOW	HELL C	1	1.	-1.	133.1	206
HELL C	LR.GRN	1	24.	2.	278.3	450
DWRSHK	LR.GRN	1	12.	-1.	-1.0	450
LR.GRN	L GOOS	1	1.	70.	270.0	930
L GOOS	LR MON	1	1.	70.	300.0	928
LR MON	ICE H	1	1.	70.	208.0	922
ICE H	MCNARY	1	1.	20.	240.0	693
MCNARY	J DAY	1	3.	150.	2239.2	1127
J DAY	DALLES	1	1.	200.	2400.0	2484
RND B	PELTON	1	1.	-1.	-1.0	300

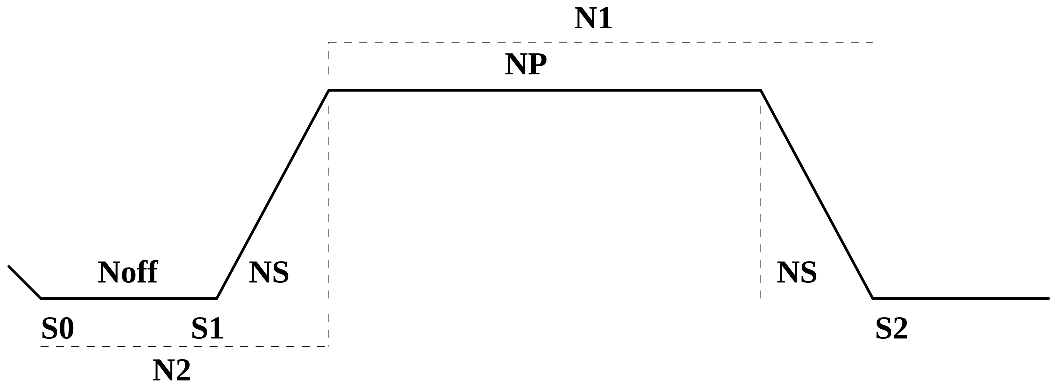
PELTON	DALLES	1	18.	-1.	46.0	120
DALLES	BONN	1	2.	150.	635.0	2050
BONN		1		16.7	1716.0	1186
SWFT 1	SWFT 2	1	1.	-1.	-1.0	268
SWFT 2	YALE	1	1.	-1.	0.0	76
YALE	MERWIN	1	1.	-1.	2294.4	133
MERWIN		1		-1.	2200.8	149

Second Section of SYSTEM.DEF

Project	HK	FG	HK	FG	HK	FG	HK	FG
H HORS	34.85	12.08	32.25	11.62	28.51	11.46	17.15	7.72
KERR	14.12	11.33	13.36	11.41	13.10	11.30	12.13	11.79
THOM F	0.00	11.00						
NOXON	11.48	48.25	10.50	46.98	8.57	43.59		
CAB G	0.0	35.70						
ALBENI	1.88	26.66	1.46	25.55	1.19	23.88	0.96	22.04
BOX C	0.0	29.						
BOUND	0.0	53.						
LIBBY	25.07	23.93	20.37	27.78	9.97	12.77	9.33	12.29
COULEE	23.09	277.76	22.03	282.85	17.96	257.34	16.62	250.02
CH JOE	0.0	215.						
WELLS	0.0	220.						
CHELAN	26.15	2.06	25.37	2.05	24.28	2.03		
R RECH	0.0	220.						
ROCK I	0.0	220.						
WANAP	0.0	178.						
PRIEST	0.0	187.						
BRNLEE	16.88	39.98	15.50	40.16	12.70	38.74	11.50	37.57
OXBOW	0.0	25.						
HELL C	0.0	30.						
DWRSHK	47.99	9.37	41.51	10.72	40.51	10.79	34.43	10.37
LR.GRN	7.18	129.51	5.98	143.13	3.84	131.85	2.75	105.75
L GOOS	7.01	132.32	5.99	143.14	4.22	138.00	2.62	101.74
LR MON	6.92	133.42	6.02	142.39	4.38	139.82	2.66	102.53
ICE H	5.71	121.40	5.11	110.29	3.86	103.02	3.15	101.45
MCNARY	0.0	232.						
J DAY	6.72	369.68	6.62	374.34				
RND B	24.45	12.25	20.04	10.56				
PELTON	0.0	11.2						
DALLES	0.0	375.						
BONN	0.0	288.						
SWFT 1	29.40	9.12	26.49	8.62	23.00	7.80	20.19	6.93
SWFT 2	0.0	7.92						
YALE	18.15	7.33	16.99	7.05	16.10	6.87	14.53	6.47
MERWIN	13.90	10.66	13.31	10.31	11.76	9.59		

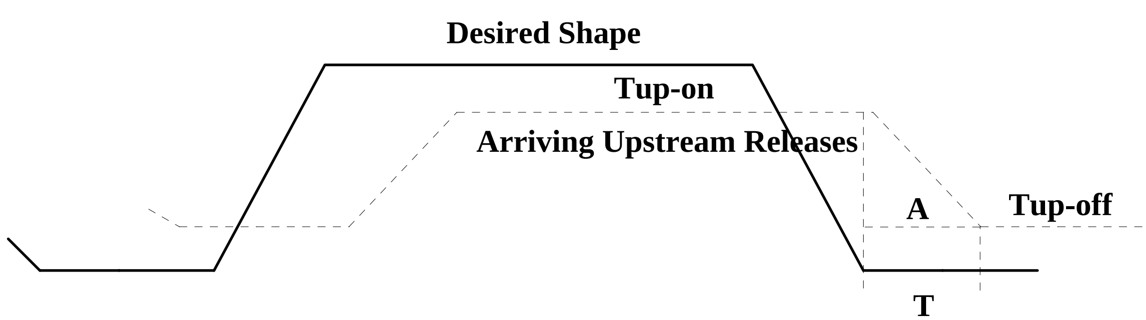
DRAFT

Appendix A4
Description of the Trapezoid



NP = number of peak hours
NS = number of shoulder hours, equal shoulders in morning and evening
N1 = NP + NS (Total on-peak time)
N2 = 24 - N1 (Total off-peak time)
Noff = 24 - NP - 2*NS (night time hours)

NOTE: N1, N2 and Noff are constants that facilitate the formulation of the linear program.



In this diagram, the desired shape and the arriving upstream releases are graphed as a function of time. Given time "T," storage available at the project can only be used to increase the on-peak flows to the extent that it exceeds the area "A." If the storage capability of the project is less than "A," then the extended peaking capability of the project must be reduced. The energy reduction in the on-peak period is given by:

A = Fdif*Tterm (KCFS-HRS)
where Fdif = Tup-on + Sup-on - Tup-of - Sup-of
and;

Tterm = T*T/2/NS	for 0 <= T <= NS
Tterm = T - NS/2	for NS <= T <= Noff
Tterm = T - NS/2 - (T - Noff)^2/2/NS	for Noff <= T <= N2

Tterm = Noff for N2 <= T <= 12

NOTE: For time delays greater than 8 hours, the shape of the arriving upstream flows is thought to be lost and thusly arrives flat.