

Appendix F

Sub-Daily CROME Synopsis

Sub-daily CROME model formulation & parameterization

The Sub-Daily Connecticut River Optimization Modeling Environment (Sub-daily CROME) is formulated in the proprietary LINGO™ optimization software environment. LINGO™ provides a modeling environment where optimization problems are intuitively formulated using the software's set-based modeling language and solved using the software's suite of linear, binary, and nonlinear optimization algorithms (LINDO Systems 2010). The Sub-daily CROME model uses the simplex-based solver to solve the linear program (LP) hydropower optimization formulation and takes advantage of LINGO's™ interactive data management capabilities to import modeled input data from a Visual Basic for Applications (VBA) enabled Microsoft Excel workbook. The following sections explain the Sub-daily CROME modeling environment, the components of the LP formulation, the scripts used to model the Baseline and Run-of-River scenarios, and important model parameters.

General model structure

The major components of the Sub-daily CROME modeling environment include model inputs, modeling procedure, and post-processing. Figure 1 shows the general structure of the Sub-daily CROME modeling framework, including flow and energy price as inputs to the coupled Excel- LINGO™ model and post processing in the open-source R coding language. Model inputs are housed within the large, 150 megabyte spreadsheet which contains hourly flow and energy price data as well as documented physical and operating

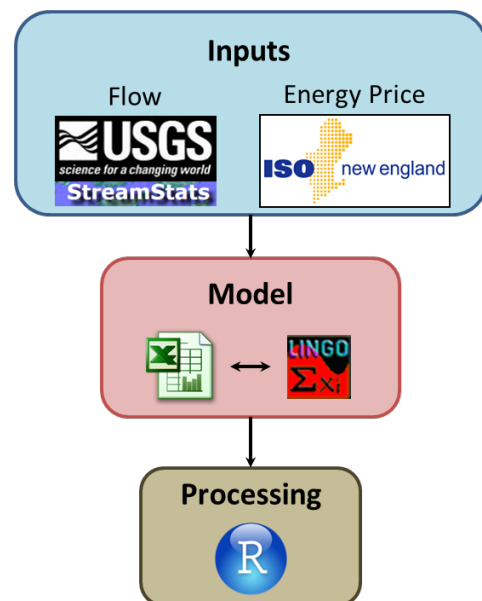


Figure 1 - Schematic of the generalized Sub-daily CROME workflow

parameters used to constrain the hydropower optimization objective. Using a VBA script, these data are passed to the LINGO™ model, and hydropower optimization is executed at yearly increments. Modeled output is aggregated in simple text files for post-processing in the R coding environment where necessary data adjustments can be made before performing model analyses.

LP formulation

The following section defines the unique components of the linear program formulation for Sub-daily CROME including the objective function formulation and operational constraints used to limit hydropower operations to real-world operations in the order presented in the LINGO™ script defined in the next section.

Objective function

Simply stated, the hydropower optimization objective is formulated to maximize revenue from hydropower dams as described in the main document. For each year of hydropower optimization, the objective function maximizes the aggregate revenues of the modeled five dams at the hourly time step. Within the objective function, weights are associated with each of the hydropower facilities such that the relative importance of these facilities can be operated correctly. For instance, releases from Vernon Dam supply water to Northfield and since Northfield may generate three times the revenue of Vernon, the optimization may unintelligently choose operations which maximize Northfield revenues at a detriment to Vernon's. In order to ensure normal operations, the objective weight for Vernon is scaled to be three times as large as Northfield, encouraging the model to model intuitive hydropower operations.

While only the hydropower objective was used in this study, the model is easily formulated for a multi-objective approach which allows for the consideration of explicit ecological objectives. A version of this model already exists, though this ecological objective was not of interest to

ecological stakeholders in its current form. The opportunity to reformulate and use this multi-objective approach to explicitly consider trade-offs between ecological and hydropower objectives is a basis for future work.

Model constraints

To ensure that Sub-daily CROMES accurately mimics operations on the current hydropower system, various physical and operational constraints are applied to the model to define the basic functional components of hydropower facilities and their operation.

Continuity

A mass balance is applied at each modeled reservoir to ensure continuity of flows and water storage along the mainstem. The mass balance constraint simply states that the storage of any given reservoir is the summation of its storage at the previous time step and its inflows and releases at the current time step. To ensure continuity of reservoir storage across modeled years, the initial and final storages are constrained to the same value for each year.

Physical and operating constraints

Each facility is constrained to its physical limitations including useable reservoir storage, maximum turbine flow rate, and maximum power generating capacity. Operating constraints are applied in the form of licensed minimum flows and hydropower release ramping rates. The ramping rates are applied to ensure realistic hydropower generation at levels matching closely to historically reported power generation.

Baseline LINGO script

The following section shows the LINGO™ script code for the objective and constraint formulation of the Baseline model, designed to mimic real-world hydropower operations for the FERC relicensing system. Both the programming language and the variable nomenclature follow an intuitive scheme which is supported by commented explanations. Variables names follow the

general format: TYPE_LOCATION_VARIABLE where the TYPE is most generally RES for reservoir, the LOCATION is some character set such as WILD for Wilder Dam, and VARIABLE may be PR for power release or ST_MAX for storage maximum.

```
!---Objective Function---;

MIN =
!Maximize Income from Hydropower Projects;
-RES_WILD_P_WT * @SUM(hour(I): RES_WILD_INC(I)) - !Wilder Total Income;
RES_BFAL_P_WT * @SUM(hour(I): RES_BFAL_INC(I)) - !Bellows Falls Total Income;
RES_VERN_P_WT * @SUM(hour(I): RES_VERN_INC(I)) - !Vernon Total Income;
RES_NORT_P_WT * @SUM(hour(I): RES_NORT_INC(I)) - !Northfield Total Income;
RES_TURN_P_WT * @SUM(hour(I): RES_TURN_INC(I)) + !Turners Falls Total Income;
!Minimize Pumping Cost @ Northfield;
RES_NORT_INTAKE_WT * @SUM(hour(I): RES_NORT_INTAKE_COST(I)) + !Northfield Intake Cost;
;
!-----;

!---Model Constraints---;

!Reservoir Mass Balance;
! (Reservoir Storage = Previous Storage + Side Inflows + Upstream Releases - Reservoir
Releases;
@FOR (hour(I) | I #GE# 2:
RES_WILD_ST(I) = RES_WILD_ST(I-1) + FLOW_WILD_SIDE(I) - RES_WILD_R(I);
RES_BFAL_ST(I) = RES_BFAL_ST(I-1) + RES_WILD_R(I) + FLOW_BFAL_SIDE(I) - RES_BFAL_R(I);
RES_VERN_ST(I) = RES_VERN_ST(I-1) + RES_BFAL_R(I) + FLOW_VERN_SIDE(I) - RES_VERN_R(I);
RES_NORT_ST(I) = RES_NORT_ST(I-1) + RES_NORT_INTAKE(I) - RES_NORT_R(I);
RES_TURN_ST(I) = RES_TURN_ST(I-1) + RES_VERN_R(I) + FLOW_TURN_SIDE(I) - RES_TURN_R(I)
- RES_NORT_INTAKE(I) + RES_NORT_R(I);
);

!Constrain Initial and Final Storages;
! (ensure consistency across each modeled year);
@FOR (hour(I) | I #EQ# 1:
RES_WILD_ST(I) = RES_WILD_ST_MAX; !13350 acre-ft;
RES_BFAL_ST(I) = RES_BFAL_ST_MAX; !7476 acre-ft;
RES_VERN_ST(I) = RES_VERN_ST_MAX; !18300 acre-ft;
RES_NORT_ST(I) = RES_NORT_ST_MAX; !12318 acre-ft;
RES_TURN_ST(I) = RES_TURN_ST_MAX; !21500 acre-ft;
);

@FOR (hour(I) | I #EQ# 8760:
RES_WILD_ST(I) = RES_WILD_ST_MAX; !13350 acre-ft;
RES_BFAL_ST(I) = RES_BFAL_ST_MAX; !7476 acre-ft;
RES_VERN_ST(I) = RES_VERN_ST_MAX; !18300 acre-ft;
RES_NORT_ST(I) = RES_NORT_ST_MAX; !12318 acre-ft;
RES_TURN_ST(I) = RES_TURN_ST_MAX; !21500 acre-ft;
);

!Storage Operating Range;
! (define useable storage capacity);
@FOR (hour(I) | I #GE# 1:
RES_WILD_ST(I) < RES_WILD_ST_MAX; !13350 acre-ft;
RES_BFAL_ST(I) < RES_BFAL_ST_MAX; !7476 acre-ft;
RES_VERN_ST(I) < RES_VERN_ST_MAX; !18300 acre-ft;
RES_NORT_ST(I) < RES_NORT_ST_MAX; !12318 acre-ft;
RES_TURN_ST(I) < RES_TURN_ST_MAX; !21500 acre-ft;
```

```

);

!Minimum Flows;
! (ensure licensed minimum flow conditions are always met);
@FOR (hour(I) | I #GE# 1:
RES_WILD_R(I) > RES_WILD_R_MIN;
RES_BFAL_R(I) > RES_BFAL_R_MIN;
RES_VERN_R(I) > RES_VERN_R_MIN;
RES_TURN_R(I) > RES_TURN_R_MIN;
);

!Releases;
! (Release term R includes SPILL + PR (Power Release). This ensures R >= PR);
! (SPILL is not an explicitly defined term, but implied through this relationship such
that when R > PR, SPILL = R-PR);
@FOR (hour(I) | I #GE# 1:
RES_WILD_R(I) >= RES_WILD_PR(I);
RES_BFAL_R(I) >= RES_BFAL_PR(I);
RES_VERN_R(I) >= RES_VERN_PR(I);
RES_NORT_R(I) = RES_NORT_PR(I);
RES_TURN_R(I) >= RES_TURN_PR(I);
);

!Constrain flow through turbines;
@FOR (hour(I) | I #GE# 1:
RES_WILD_PR(I) < RES_WILD_PR_MAX; !10,500 cfs maximum turbine capacity;
RES_BFAL_PR(I) < RES_BFAL_PR_MAX; !10,700 cfs maximum turbine capacity;
RES_VERN_PR(I) < RES_VERN_PR_MAX; !15,000 cfs maximum turbine capacity;
RES_NORT_PR(I) < RES_NORT_PR_MAX; !3,800 (x4) cfs turbine capacity;
RES_TURN_PR(I) < RES_TURN_PR_MAX; !16,000 cfs is design flow of the canal;
);

!Release Ramping - limit ramp rates for realistic hydropeaking power release;
! (With ramp rates unconstrained, power releases would exhibit blocky (On/Off) release
behavior);
! (Unique ramping rates were chosen for each facility to calibrate average annual
power production to historic rates);
@FOR (hour(I) | I #GE# 2:
! Ramping up constraint;
[RES_WILD_PR_UP] RES_WILD_PR(I) - RES_WILD_PR(I-1) < RES_WILD_RAMP_UP;
[RES_BFAL_PR_UP] RES_BFAL_PR(I) - RES_BFAL_PR(I-1) < RES_BFAL_RAMP_UP;
[RES_VERN_PR_UP] RES_VERN_PR(I) - RES_VERN_PR(I-1) < RES_VERN_RAMP_UP;

[RES_NORT_PR_UP] RES_NORT_PR(I) - RES_NORT_PR(I-1) < RES_NORT_RAMP_UP;
[RES_NORT_IN_UP] RES_NORT_INTAKE(I) - RES_NORT_INTAKE(I-1) < RES_NORT_RAMP_UP;

[RES_TURN_PR_UP] RES_TURN_PR(I) - RES_TURN_PR(I-1) < RES_TURN_RAMP_UP;

! Ramping down constraint;
[RES_WILD_PR_DN] RES_WILD_PR(I-1) - RES_WILD_PR(I) < RES_WILD_RAMP_DOWN;
[RES_BFAL_PR_DN] RES_BFAL_PR(I-1) - RES_BFAL_PR(I) < RES_BFAL_RAMP_DOWN;
[RES_VERN_PR_DN] RES_VERN_PR(I-1) - RES_VERN_PR(I) < RES_VERN_RAMP_DOWN;

[RES_NORT_PR_DN] RES_NORT_PR(I-1) - RES_NORT_PR(I) < RES_NORT_RAMP_DOWN;
[RES_NORT_IN_DN] RES_NORT_INTAKE(I-1) - RES_NORT_INTAKE(I) < RES_NORT_RAMP_DOWN;

[RES_TURN_PR_DN] RES_TURN_PR(I-1) - RES_TURN_PR(I) < RES_TURN_RAMP_DOWN;
);

!Constrain power generated;
! (Define maximum power capacity of each facility);
@FOR (hour(I) | I #GE# 1:

```

```

RES_WILD_P(I) < RES_WILD_P_MAX;
RES_BFAL_P(I) < RES_BFAL_P_MAX;
RES_VERN_P(I) < RES_VERN_P_MAX;
RES_NORT_P(I) < RES_NORT_P_MAX;
RES_TURN_P(I) < RES_TURN_P_MAX;
);

!Calculate the power production;
@FOR (hour(I) | I #GE# 1:
! CONV term = PR_MAX/(P_MAX * efficiency);
RES_WILD_P(I) = RES_WILD_PR(I)/RES_WILD_P_CONV; !334 cfs per MW produced;
RES_BFAL_P(I) = RES_BFAL_PR(I)/RES_BFAL_P_CONV; !349 cfs per MW produced;
RES_VERN_P(I) = RES_VERN_PR(I)/RES_VERN_P_CONV; !644 cfs per MW produced;
RES_NORT_P(I) = RES_NORT_PR(I)/RES_NORT_P_CONV; !23 cfs per MW produced;
RES_TURN_P(I) = RES_TURN_PR(I)/RES_TURN_P_CONV; !295 cfs per MW produced;
);

!Reservoir Income;
! (Revenue calculated from product of estimated power and historic energy price);
@FOR (hour(I) | I #GE# 1:
RES_WILD_INC(I) = RES_WILD_P(I) * ENERGY_PRICE(I);
RES_BFAL_INC(I) = RES_BFAL_P(I) * ENERGY_PRICE(I);
RES_VERN_INC(I) = RES_VERN_P(I) * ENERGY_PRICE(I);
RES_NORT_INC(I) = RES_NORT_P(I) * ENERGY_PRICE(I);
RES_TURN_INC(I) = RES_TURN_P(I) * ENERGY_PRICE(I);
);

!Northfield Power Intake;
! (Modeling Northfield's pumped storage operations requires an INTAKE term to define
flow rates, power, & costs associated pumping water up to the facility);
@FOR (hour(I) | I #GE# 1:
! Define limits for INTAKE flow term between 0 and MAX (15,000 cfs);
@BND(0,RES_NORT_INTAKE(I), RES_NORT_INTAKE_MAX);
! Define INTAKE_P power generation term;
! (the power conversion ratio (cfs/MW) for pumping water is ~4/3 the ratio used for
power generated using release);
! (pg. 99/537 of the Firstlight FERC Pre-Application document defines this
relationship (17.9 cfs/13.6 cfs ~ 4/3));
RES_NORT_INTAKE_P(I) = (RES_NORT_INTAKE(I)/RES_NORT_P_CONV)*4/3;
!Conversion from power generation to power cost;
RES_NORT_INTAKE_COST(I) = RES_NORT_INTAKE_P(I)*ENERGY_PRICE(I););
!-----;

```

Run-of-River LINGO script

The following section shows the changes in the LINGO™ script from the Baseline model to the Run-of-River system. The objective formulation remains the same as in the Baseline scenario, though mainstem facility operations are constrained such hydropower releases may not be optimized at these locations. Constraints which were removed from the Baseline run are shown in ~~strike through~~ and added constraints are shown in normal text below.

```

!Release Ramping—limit ramp rates for realistic hydropeaking power release+
!(With ramp rates unconstrained, power releases would exhibit blocky (On/Off) release
behavior+;
!(Unique ramping rates were chosen for each facility to calibrate average annual
power production to historic rates+;
@FOR (hour(I) | I #CE# 2+
! Ramping up constraint+
[RES_WILD_PR_UP] RES_WILD_PR(I) — RES_WILD_PR(I-1) < RES_WILD_RAMP_UP+;
[RES_BFAL_PR_UP] RES_BFAL_PR(I) — RES_BFAL_PR(I-1) < RES_BFAL_RAMP_UP+;
[RES_VERN_PR_UP] RES_VERN_PR(I) — RES_VERN_PR(I-1) < RES_VERN_RAMP_UP+;

[RES_NORT_PR_UP] RES_NORT_PR(I) — RES_NORT_PR(I-1) < RES_NORT_RAMP_UP+;
[RES_NORT_IN_UP] RES_NORT_INTAKE(I) — RES_NORT_INTAKE(I-1) < RES_NORT_RAMP_UP+;

[RES_TURN_PR_UP] RES_TURN_PR(I) — RES_TURN_PR(I-1) < RES_TURN_RAMP_UP+;

! Ramping down constraint+
[RES_WILD_PR_DN] RES_WILD_PR(I-1) — RES_WILD_PR(I) < RES_WILD_RAMP_DOWN+;
[RES_BFAL_PR_DN] RES_BFAL_PR(I-1) — RES_BFAL_PR(I) < RES_BFAL_RAMP_DOWN+;
[RES_VERN_PR_DN] RES_VERN_PR(I-1) — RES_VERN_PR(I) < RES_VERN_RAMP_DOWN+;

[RES_NORT_PR_DN] RES_NORT_PR(I-1) — RES_NORT_PR(I) < RES_NORT_RAMP_DOWN+;
[RES_NORT_IN_DN] RES_NORT_INTAKE(I-1) — RES_NORT_INTAKE(I) < RES_NORT_RAMP_DOWN+;

[RES_TURN_PR_DN] RES_TURN_PR(I-1) — RES_TURN_PR(I) < RES_TURN_RAMP_DOWN+;
+;

!Run of river condition (releases = inflows);
@FOR (hour(I) | I #GE# 2+
RES_WILD_R(I) = FLOW_WILD_SIDE(I);
RES_BFAL_R(I) = RES_WILD_R(I) + FLOW_BFAL_SIDE(I);
RES_VERN_R(I) = RES_BFAL_R(I) + FLOW_VERN_SIDE(I);
RES_TURN_R(I) = RES_VERN_R(I) + FLOW_TURN_SIDE(I);
);

```


Model Parameterization

The following section shows the values of the various modeled parameters used in the above reservoir modeling formulations. The values are derived from documentation on each reservoir found in FERC pre application documents.

Reservoir Data

Minimum Release		
RES_WILD_R_MIN	675	<i>cfs</i>
RES_BFAL_R_MIN	1,083	<i>cfs</i>
RES_VERN_R_MIN	1,250	<i>cfs</i>
RES_NORT_R_MIN	N/A	<i>cfs</i>
RES_TURN_R_MIN	1,250	<i>cfs</i>
Maximum Turbine Release		
RES_WILD_PR_MAX	10,700	<i>cfs</i>
RES_BFAL_PR_MAX	11,400	<i>cfs</i>
RES_VERN_PR_MAX	17,100	<i>cfs</i>
RES_NORT_PR_MAX	20,000	<i>cfs</i>
RES_TURN_PR_MAX	16,000	<i>cfs</i>
Maximum Pumping Rate		
RES_NORT_INTAKE_MAX	15,200	<i>cfs</i>
Ramping		
RES_WILD_RAMP_UP	1,111	<i>cfs</i>
RES_WILD_RAMP_DOWN	1,111	<i>cfs</i>
RES_BFAL_RAMP_UP	1,111	<i>cfs</i>
RES_BFAL_RAMP_DOWN	1,111	<i>cfs</i>
RES_VERN_RAMP_UP	1,111	<i>cfs</i>
RES_VERN_RAMP_DOWN	1,111	<i>cfs</i>
RES_NORT_RAMP_UP	1,800	<i>cfs</i>
RES_NORT_RAMP_DOWN	1,800	<i>cfs</i>
RES_TURN_RAMP_UP	1,111	<i>cfs</i>
RES_TURN_RAMP_DOWN	1,111	<i>cfs</i>
Max Operating Storage		
RES_WILD_ST_MAX	13,350	<i>acre-ft</i>
RES_BFAL_ST_MAX	7,476	<i>acre-ft</i>
RES_VERN_ST_MAX	18,300	<i>acre-ft</i>
RES_NORT_ST_MAX	12,318	<i>acre-ft</i>
RES_TURN_ST_MAX	7,400	<i>acre-ft</i>

Power Data

Maximum Power Generation		
RES_WILD_P_MAX	35.6	<i>MW</i>
RES_BFAL_P_MAX	48.6	<i>MW</i>
RES_VERN_P_MAX	32.4	<i>MW</i>
RES_NORT_P_MAX	1119	<i>MW</i>
RES_TURN_P_MAX	67.7	<i>MW</i>
General Turbine Efficiency		
RES_WILD_EFF	0.9	<i>ratio (MW generator/MW turbine)</i>
RES_BFAL_EFF	0.8	<i>ratio (MW generator/MW turbine)</i>
RES_VERN_EFF	0.82	<i>ratio (MW generator/MW turbine)</i>
RES_NORT_EFF	0.88	<i>ratio (MW generator/MW turbine)</i>
RES_TURN_EFF	0.9	<i>ratio (MW generator/MW turbine)</i>
cfh per MW (=Max Turbine Release/(Max MW x Efficiency))		
RES_WILD_P_CONV	334	<i>cfs/MW</i>
RES_BFAL_P_CONV	293	<i>cfs/MW</i>
RES_VERN_P_CONV	644	<i>cfs/MW</i>
RES_NORT_P_CONV	20	<i>cfs/MW</i>
RES_TURN_P_CONV	263	<i>cfs/MW</i>

