ANL/DIS-13/05



Review of Existing Hydroelectric Turbine-Governor Simulation Models

Decision and Information Sciences

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Review of Existing Hydroelectric Turbine-Governor Simulation Models

prepared for
U.S. Department of Energy – Wind and Water Power Technologies Office

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Preface

This report is one of several reports developed during the U.S. Department of Energy (DOE) study on the Modeling and Analysis of Value of Advanced Pumped Storage Hydropower in the United States. The study was led by Argonne National Laboratory in collaboration with Siemens PTI, Energy Exemplar, MWH Americas, and the National Renewable Energy Laboratory. Funding for the study was provided by DOE's Office of Energy Efficiency and Renewable Energy (EERE) through a program managed by the EERE's Wind and Water Power Technologies Office (WWPTO).

The scope of work for the study has two main components: (1) development of vendor-neutral dynamic simulation models for advanced pumped storage hydro (PSH) technologies, and (2) production cost and revenue analyses to assess the value of PSH in the power system. Throughout the study, the project team was supported and guided by an Advisory Working Group (AWG) consisting of more than 30 experts from a diverse group of organizations including the hydropower industry and equipment manufacturers, electric power utilities and regional electricity market operators, hydro engineering and consulting companies, national laboratories, universities and research institutions, hydropower industry associations, and government and regulatory agencies.

The development of vendor-neutral models was carried out by the Advanced Technology Modeling Task Force Group (TFG) and was led by experts from Siemens PTI with the participation of experts from other project team members. First, the Advanced Technology Modeling TFG reviewed and prepared a summary of the existing dynamic models of hydro and PSH plants that are currently in use in the United States. This is published in the report *Review of Existing Hydroelectric Turbine-Governor Simulation Models*. The review served to determine the needs for improvements of existing models and for the development of new ones.

While it was found that the existing dynamic models for conventional hydro and PSH plants allow for accurate representation and modeling of these technologies, it was concluded that there is a need for the development of dynamic models for two PSH technologies for which there were no existing models available in the United States at the time of the study. Those two technologies are (1) adjustable speed PSH plants employing doubly-fed induction machines (DFIM), and (2) ternary PSH units. The Advanced Technology Modeling TFG developed vendor-neutral models of these two PSH technologies, which are published in two reports: (1) *Modeling Adjustable Speed Pumped Storage Hydro Units Employing Doubly-Fed Induction Machines*, and (2) *Modeling Ternary Pumped Storage Units.*

Extensive testing of newly developed models was performed using the Siemens PTI's standard test cases for the Power System Simulator for Engineering (PSS®E) model as well as the Western Electricity Coordinating Council's (WECC's) modeling cases for Western Interconnection that were provided in PSS®E format. The results of model testing are presented in the report *Testing Dynamic Simulation Models for Different Types of Advanced Pumped Storage Hydro Units*.

In addition to review by the project team members and the DOE, all these reports have been reviewed by members of the AWG, and their comments and suggestions have been incorporated into the final versions of the reports. Parts of these reports will also be included in the final report for the entire study to illustrate the model development component of the work.

Acknowledgements

The authors would like to acknowledge the support and guidance provided to the project team by the staff and contractors of the DOE/EERE's Wind and Water Power Technologies Office (WWPTO), including Michael Reed, Rajesh Dham, Charlton Clark, Rob Hovsapian, Patrick O'Connor, Richard Gilker, and others. The authors are also grateful to the members of the Advisory Working Group for their excellent collaboration and efforts in advising the project team and guiding the study. The Advisory Working Group included a broad spectrum of global pumped storage hydropower specialists including:

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Section 1

Introduction

This report is the first in a series of documents to be issued in the course of a DOE project titled "Modeling and Analysis of Value of Advanced Pumped Storage Hydropower in the U.S."

We are all intimately familiar with small energy storage devices; we use batteries of various types in our cell phones and other electronic devices as well as the more traditional battery-powered devices such as flashlights and radios. However, storing large amounts of energy, on the scale that would be useful for a utility-scale power system, has been a much more challenging task. While several new technologies are being developed, pumped storage hydro is the most widely employed method available for storing large amounts of energy to supply electricity. The basic concept of pumped storage is quite simple: electricity is used to pump water up to an elevated reservoir, where the energy can be stored as potential energy until it is needed; then electricity is generated by letting the water flow back down thorough a turbine/generator. Of course, since there is a loss of energy due to the pumping and generating cycle (as low as 10% for some new plants), there must be an economic incentive for the storage, such as a variation in electricity prices between times of pumping and generating.

Energy usage is greatly influenced by the normal schedule of people (high during the day when people are most active and low at night) and weather (high when the temperature is very hot or cold and lower when the temperature is moderate), and, of course, many other factors also influence usage. Most electricity is generated at large power stations powered by the combustion of fossil fuels, by the use of nuclear energy, and by hydroelectric plants. There is a growing, but still small in most locations, contribution from wind- and solar-based generation. While the use of electricity varies throughout the day, large generation plants run most efficiently at a constant output. Thus, it would be advantageous to run these large generators during periods of lower electricity usage and store the energy to supply electricity at periods of higher demand. An additional benefit is that these large generating stations are very capital intensive; thus, being able to store and deliver some of the energy needed at times of peak demand reduces the number of large generating stations required to supply the peak period. Therefore, there are savings in both energy costs and the capital costs of the generating stations.

The growth in the amount of energy supplied by renewable generation has increased the need for energy storage. Renewable energy sources generally are not well correlated with electricity usage. Wind energy, for example, tends to be unavailable during periods of high energy usage (e.g., there is little wind during a hot summer day when air conditioning demand is high) and to be high during periods of low electric usage (e.g., winds pick up in the evening as electricity demand falls). Energy storage thus allows the renewable energy to be generated when it is available (e.g., when the wind is blowing at night) and stored until it is needed (e.g., during periods of high demand the next day).

A third benefit is regulation. The supply and usage of electricity must be carefully balanced to maintain a frequency of 60 Hz and voltage within a narrow range. The mechanisms for this regulation are explained briefly in this report and in more detail in other reports from this project. Here we simply state that the advanced pump storage technologies that are the focus of this project have significant advantages over conventional pumped storage due to their fast controllability in both generating and pumping modes.

The benefits just described were recognized early in the development of the electric power grids, especially as systems became larger and more interconnected. The first pumped storage plant in the United States was the Rocky River Pumped Storage Station located near Milton, Connecticut, which started operation in 1929. The use of reversible pump-turbines in pumped storage plants began in the 1950s in the United States. While the design and engineering of more recent plants in the United States have improved efficiency and reduced environmental impacts, the basic design of the modern pumped storage plants in the United States is similar to that used in those earlier plants.

The objective of this overall effort is to investigate the advantages of recent advances in the design of pumped storage hydro plants. The objective of the first task of this project, “Develop Prototype Models of Advanced Pumped Storage Hydro (PSH) and Conventional Hydro (CH) Plants,” is to develop vendor-neutral dynamic simulation models for both fixed- and adjustable-speed PSH plants.

These models are a critical component of the analysis needed to plan, design, and operate the power system. Power system studies that use such models are performed to:

- Determine operating strategies and power transfer limits
- Study the impact of new generator additions
- Determine the need for new transmission lines and substations
- Investigate the stability of the system following large disturbances (transient stability) or incremental impacts (small signal stability)
- Analyze the control of frequency and/or system voltages

Thus it is very important that the models used in the above analysis be accurate. If the models are overly optimistic, the system could be operated in a manner that leads to severe consequences, including widespread disturbances or blackouts. On the other hand, if the models are overly conservative, the system could be operated uneconomically, or unnecessary system additions could be built.

It is logical to start this work with a review of the status of hydro unit modeling in the commercially available software packages used by utilities and system operators in the planning and operation of the U.S. power grid. The two software packages that dominate this market are Siemens PTI's PSS®E and GE's PSLF programs; nearly all major U.S. utilities and system operators use one of these two programs. This report summarizes the turbine-governor models for hydroelectric units present in these two software packages.

To put this modeling in perspective, this report begins with a general overview of the approach to power system stability studies in Section 1. It includes a brief description of the modeling of generators, excitation systems, and turbine-governors. This overview is followed by a description of the specific models extracted from the standard libraries of both software platforms in Section 2 and Section 3.

The report also includes a discussion on the approach to modeling conventional (fixed-speed) PSH units in Section 4.

Section 5 discusses Modeling of Conventional Pumped Storage Hydro Plants.

Section 6 contains the Bibliography.

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Section
2

Power System Dynamic Overview

This section provides a brief overview of the control systems and strategies employed to operate the power system. It also briefly describes the models used to simulate the major equipment in the generating stations. While this section is by necessity brief, there are many excellent references that give further details on these topics.

1.1 Interaction between Main Elements of Power Systems and their Controls

A power system is designed to provide adequate capability and transmission capacity to meet system demand and maintain generation reserve. Standards regarding frequency, the voltage profile, and reliability are enforced to meet required system energy quality and performance standards. Numerous power system components and associated controls are involved in maintaining constant frequency, a normal voltage profile, and desired levels of security and reliability.

Figure 2-1 shows the various systems/subsystems, their associated controls, and their functional relationships as found in typical power systems. Controls at the plant and system level are used to ensure not only local but also global regulation of the frequency and voltage or active and reactive power flows throughout the power system.

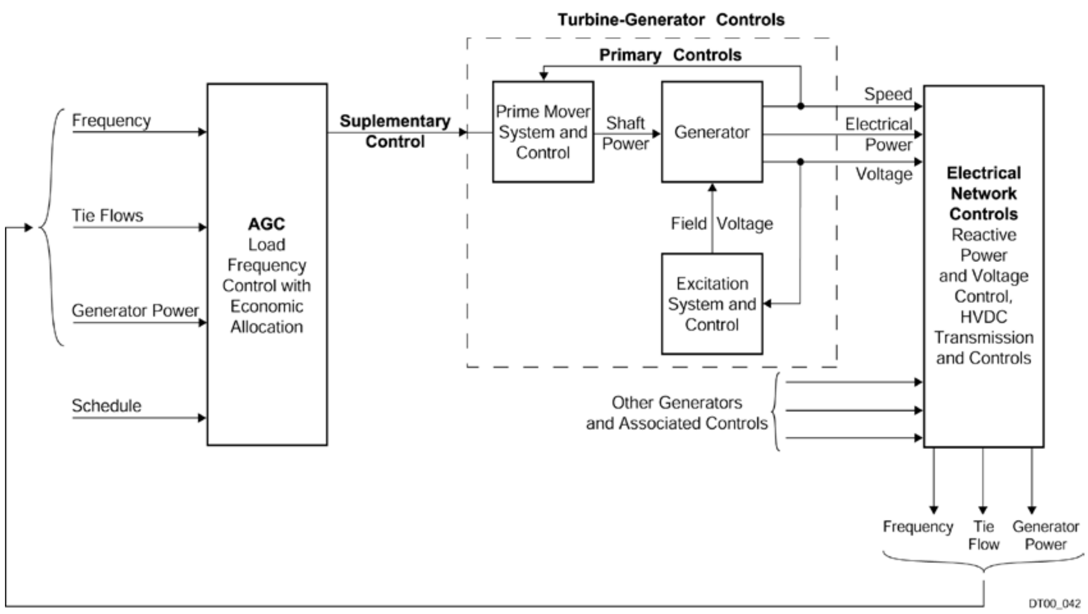


Figure 2-1 Power Plant and Network Primary and Supplementary Power System Controls

The system load frequency control (LFC) is concerned with scheduling the active power output for generating units under automatic generation control (AGC) so that system frequency and net megawatt (MW) interchange across tie-lines in the interconnected power system are maintained to comply with scheduled values. This is accomplished by matching the total active power generation to the total system MW load and active power losses.

Generator controls are concerned with voltage regulation and reactive power control. The main objective of the excitation system, automatic voltage regulator (AVR), and exciter is to regulate the generator terminal voltage by controlling field voltage. The excitation system may include a load compensator that allows regulation of voltage at a different point, such as inside the generator windings or the windings of the main step-up transformer unit. The voltage regulator provides the regulating and stabilizing function in the excitation system, while the exciter is the power source supplying the direct current (DC) or variable-frequency power used in the generator field windings.

Power plant and network components and their controls contribute to the proper operation of a power system by maintaining a desired frequency and voltage profile and defining the performance of the system during small and large disturbances. The control objectives are closely related to the operating states of the power system. Control objectives under normal (steady-state) conditions are to operate the system efficiently, adequately, and reliably and to keep frequency and voltage within established limits, close to nominal values. When an abnormal operating condition develops, the power system should prevent major system failures and be restored to normal operation as soon as possible.

The primary objective of the power system generation control is to balance the total generation with system demand and losses, so that frequency, active net power interchange across tie-lines, and required voltage support are maintained. Generation controls consist of the prime mover controls (governing system) and the generator controls (excitation systems).

Figure 2-2 is a schematic diagram describing the functional relationships of the synchronous generator, excitation system, and prime mover and their associated controls that are used in assessing small and large signal stability in power systems.

The modeling of each of the pieces of power plant equipment shown in Figure 2-2 is described briefly in the three subsections that follow.

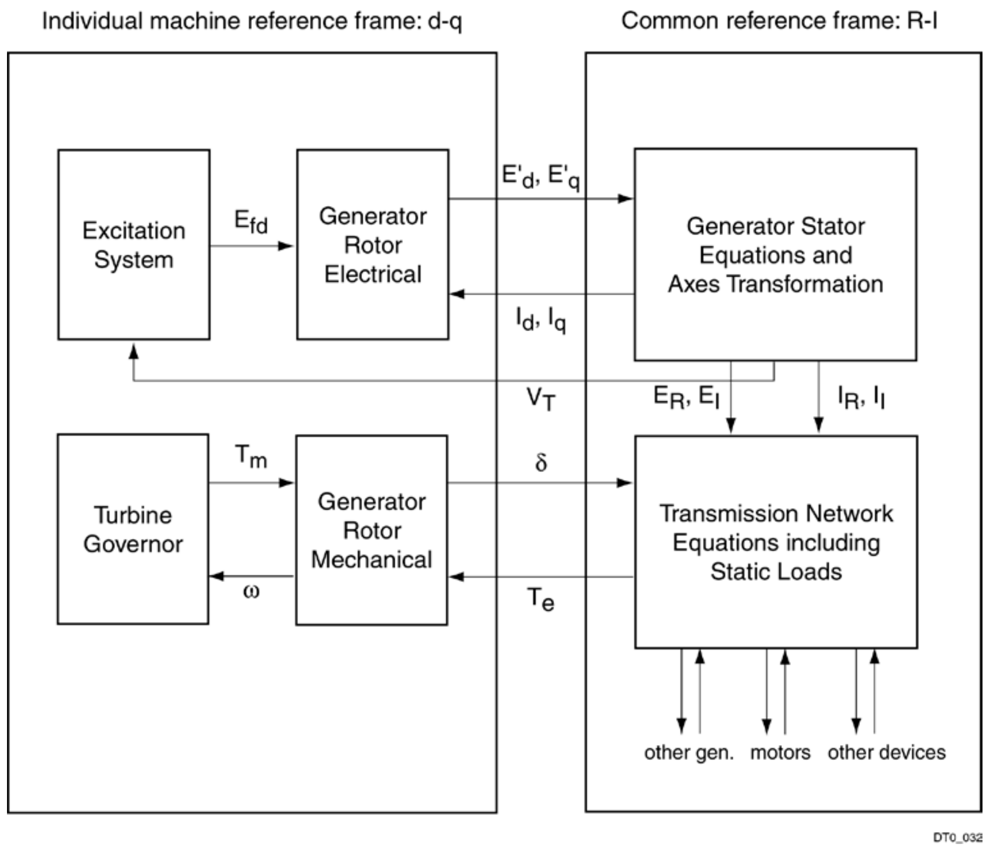


Figure 2-2 Functional Relationships among Generator, Prime Mover, and Associated Controls

2.1.1 Generators

Conventional generating units are furnished with synchronous generators driven by either high-speed turbines (gas and steam turbines) or low-speed prime movers (hydraulic and internal combustion engines). High-speed synchronous generators are designed with two or four magnetic poles and cylindrical rotors with a long axial length and small diameter. Low-speed synchronous generators (those used in hydro and pumped storage plants) are designed with rotors having a large number of salient pole pairs, a short axial length, and a large diameter. Models for synchronous generators used for large and small signal stability studies include both inertial and rotor circuits flux dynamics.

Power system simulation commercial software (PSS®E, PSLF, and others) use a fifth-order dynamic model for salient pole rotor generators, with three state variables related to rotor circuits flux dynamics (field and damper windings) and two-state variables related to the mechanics of rotating motion. For the round rotor (high-speed) generator, the model uses six-state variables, with four for the electromagnetic dynamics (fluxes linkages and induced voltages associated with the main field winding and damper windings) and two for the rotor mechanical motion (rotor speed and angle). The name given to the most commonly used dynamic model for synchronous generators with a salient rotor design is GENSAL, and that used for round rotor design is GENROU. The magnetic saturation of the stator and rotor iron used with these models is described by a quadratic function (an exponential function is also used in other similar models). In addition, the combined inertia of all equipment mounted on the unit shaft system (generator, turbine, and exciter, if it is of the rotating type) is used in these models.

The data sheet for the salient pole generator model GENSAL is shown in Figure 2-3, and the data sheet for the round rotor generator model GENROU is shown in Figure 2-4.

Both models use standard circuit parameters, reactances, and time constants that describe the rotor circuits flux dynamics seen during the subtransient, transient, and steady-state periods following a disturbance of the power system.

GENSAL

Salient Pole Generator Model (Quadratic Saturation on d-Axis)

This model is located at system bus #_____ IBUS,

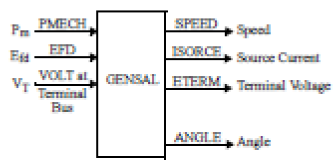
Machine identifier #_____ ID,

This model uses CONs starting with #_____ J,

and STATEs starting with #_____ K.

The machine MVA is _________ for each of units = _________ MBASE.

ZSORCE for this machine is _________ + j _________ on the above MBASE.



STATEs	#	Description
K		E'_q
K+1		ψkd
K+2		$\psi''q$
K+3		Δ speed (pu)
K+4		Angle (radians)

IBUS, 'GENSAL', ID, CON(J) to CON(J+11) /

CONs	#	Value	Description
J			T'_{do} (>0) (sec)
J+1			T''_{do} (>0) (sec)
J+2			T''_{qo} (>0) (sec)
J+3			H, Inertia
J+4			D, Speed damping
J+5			X_d
J+6			X_q
J+7			X'_d
J+8			$X''_d = X''_q$
J+9			X_l
J+10			S(1.0)
J+11			S(1.2)

Note: X_d, X_q, X'_d, X''_d, X''_q, X_l, H, and D are in pu, machine MVA base.

X''_q must be equal to X''_d.

Figure 2-3 Datasheet of the Salient Pole Generator Model

GENROU

Round Rotor Generator Model (Quadratic Saturation)

This model is located at system bus #_____ IBUS,

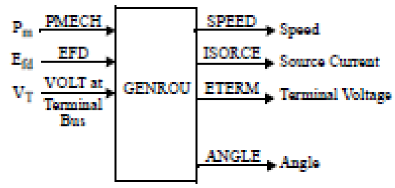
Machine identifier #_____ ID,

This model uses CONs starting with #_____ J,

and STATEs starting with #_____ K.

The machine MVA is _________ for each of __________ units = _________ MBASE.

ZSORCE for this machine is _________ + j ________ on the above MBASE



CONs	#	Value	Description
J			T'_{do} (>0) (sec)
J+1			T''_{do} (>0) (sec)
J+2			T'_{qo} (>0) (sec)
J+3			T''_{qo} (>0) (sec)
J+4			H, Inertia
J+5			D, Speed damping
J+6			X_d
J+7			X_q
J+8			X'_d
J+9			X'_q
J+10			$X''_d = X''_q$
J+11			X_l
J+12			S(1.0)
J+13			S(1.2)

Note: X_d, X_q, X'_d, X'_q, X''_d, X''_q, X_l, H, and D are in pu, machine MVA base.

X''_q must be equal to X''_d.

STATEs	#	Description
K		E'_q
K+1		E'_d
K+2		ψkd
K+3		ψkq
K+4		Δ speed (pu)
K+5		Angle (radians)

IBUS, 'GENROU', ID, CON(J) to CON(J+13) /

Figure 2-4 Datasheet of the Round Rotor Generator Model GENROU

Because the fluxes, and thus the mutual inductances, between the stator and rotor windings change with rotor position, a set of orthogonal axes ascribed to the rotor is used to make the time-varying inductances time invariant. One axis is aligned with the machine main field flux; this is the direct axis or d-axis. The second axis is set leading this axis by 90°; this is the quadrature axis or q-axis. Each generating unit rotor is thus assigned a pair of d-q axes. The angular speed associated with these axes is the rotor speed. The rotor angle associated with each generating unit is measured with respect to a common synchronously rotating pair of orthogonal axes, R and I, associated with the electrical network. These axes will thus rotate at a constant angular speed equal to $2\pi f_0$ electrical radians/s, where f_0 is the system base frequency (60 Hz for U.S. power grids).

2.1.2 Excitation Systems

The functional relationships among the fundamental components associated with the generator and its excitation system in a conventional (synchronous) generating unit are shown in Figure 2-5.

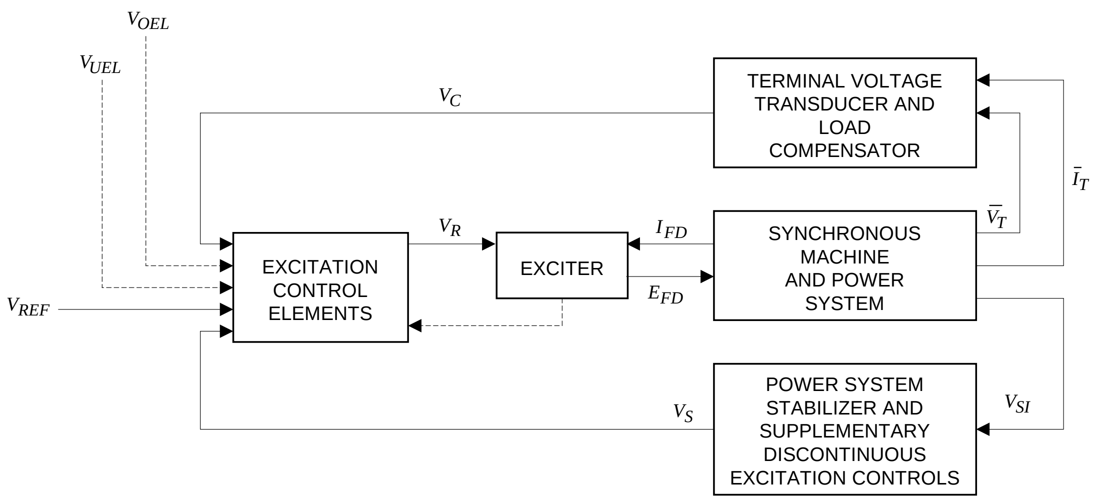


Figure 2-5 Generator and Excitation System Functional Relationships

Excitation systems found in "old" hydro power plants were usually powered with DC rotating exciters. However, static excitation systems are often being used in upgrading old facilities and in modern power plants. Excitation systems of the static type do not use rotating exciters and thus have a much faster dynamic response and a larger field forcing capability to respond to large disturbances without exceeding generator field current limits. However, because of the high initial response, they require voltage regulators with high gains that may have an adverse impact on the damping of electromechanical oscillatory modes in power systems. Power system stabilizers are often used as supplementary controls to add positive damping to the affected oscillatory modes through the excitation system by adding an electric torque in phase with the generator rotor speed. Additional control and protection systems used in excitation systems include field current limiters, terminal voltage limiters, under-excitation and over-excitation limiters (UELs and OELs), and flux (V/Hz) limiters and relays.

There are more than 50 excitation system models in the PSS®E and PSLF libraries that cover the spectrum of devices, starting from the oldest DC excitation systems to modern systems based on power electronics. These models have been defined and refined by a series of the Institute of Electrical and Electronic Engineers (IEEE) working groups over the last 40 years. The most recent models are described in IEEE Standard 421.5-2005.

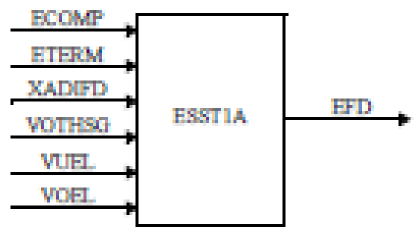
As noted above, static excitation systems are commonly used for modern hydro units. In static excitation systems, the DC source is a rectifier bridge (controlled or uncontrolled), and all components are stationary. The excitation current is fed directly to the generator through collector rings. The supply of power to the rectifier bridge can be from the main generator (through a transformer) or from auxiliary generator windings.

One example of a static excitation system, the ESST1A model, is shown in Figure 2-6. This model includes a simplified representation of the AVR and the rectifier bridge controls.

ESST1A

IEEE Type ST1A Excitation System

This model is located at system bus #______ IBUS,
Machine identifier #______ ID,
This model uses CONs starting with #______ J,
and STATEs starting with #______ K,
and ICONs starting with #______ M.



CONs	#	Value	Description
J			T_R (sec)
J+1			V_{IMAX}
J+2			V_{IMIN}
J+3			T_C (sec)
J+4			T_B (sec)
J+5			T_{C1} (sec)
J+6			T_{B1} (sec)
J+7			K_A
J+8			T_A (sec)
J+9			V_{AMAX}
J+10			V_{AMIN}
J+11			V_{RMAX}
J+12			V_{RMIN}
J+13			K_C
J+14			K_F
J+15			$T_F > 0$ (sec)
J+16			K_{LR}
J+17			I_{LR}

Figure 2-6 Excitation System Model ESST1A

STATEs	#	Description
K		$V_{measured}$
K+1		First lead lag
K+2		Second lead lag
K+3		V_A
K+4		Feedback

ICONs	#	Value	Description
M			UEL (1, 2, or 3)
M+1			VOS (1 or 2)

IBUS, 'ESST1A', ID, ICON(M), ICON(M+1), CON(J) to CON(J+17) /

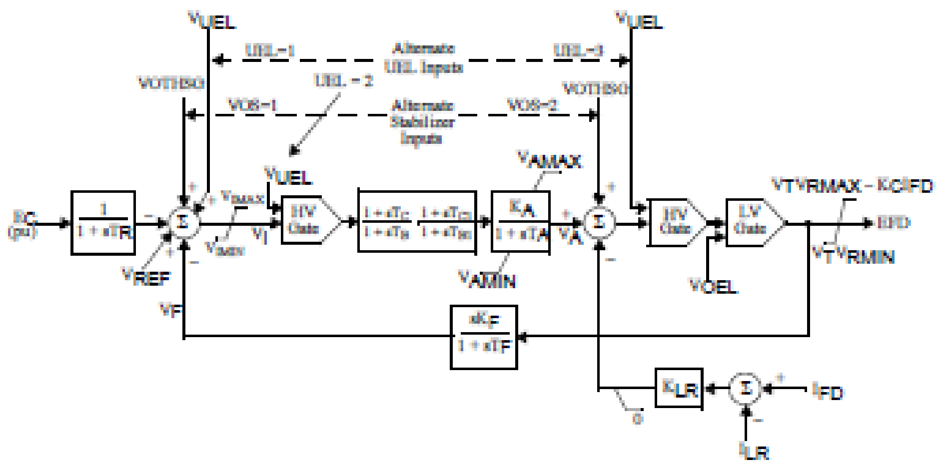


Figure 2-6 Excitation System Model ESST1A (Cont.)

2.1.3 Governor and Prime Mover Controls

Prime mover controls are concerned with regulating speed and controlling the energy supply system variables. For hydro turbine generators, the variables include head and flow. For thermal units, variables may include boiler pressure, temperature, and flow. The main function of the governing system is to regulate system frequency by controlling the prime mover's mechanical power output. Thus, its controlling input signal is shaft speed, and the controlled output variable is mechanical power output, which is converted into electrical power by the generator unit. Energy systems often used in conventional power plants are based on fossil fuels, such as natural gas, oil, coal, and water. The thermal energy available in fossil fuels is transformed into high-pressure and high-temperature steam or gas, which expands in the prime mover. The resulting kinetic energy is then converted to mechanical power available on the shaft of the prime mover. Conventional and pumped storage hydro plants employing water as a working fluid use the potential energy available in the hydraulic head at the prime mover wicket gates, so the resulting kinetic energy in the turbine's runner is converted to mechanical power available on the shaft of the prime mover.

The functional relationships among the fundamental components associated with the turbine, its governing system, and the generator in a conventional generating unit are shown in Figure 2-7.

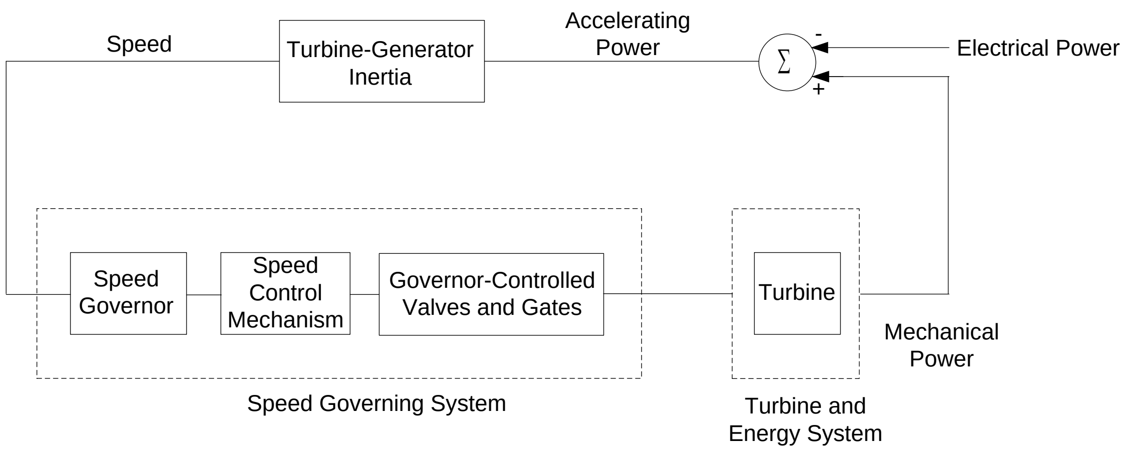


Figure 2-7 Turbine, Governor System, and Generator Functional Relationships

Because of the wide variety of designs found in turbine controls, the turbine-governor models are not designed to provide a high degree of accuracy with regard to any particular plant; rather, they represent the principal dynamic effects of the energy source and prime mover, with its associated controls, in power plants.

Section 2.2 describes the models used to represent hydroelectric governors.

1.2 Hydroelectric Generating Plants

Since the focus of this project is hydroelectric power plants, it is appropriate to give a general overview of the different types of hydroelectric units employed. There are two basic types of hydroelectric turbines: impulse turbines and reaction turbines.

Impulse turbines are generally used for installations where there is high head (head is the effective height between the water source and the turbine) and where the flow is relatively low (compared to that of the other turbine types described below). The water is focused and directed though a nozzle, and the water stream impacts the turbine blades, thereby forcing the turbine to spin. Generally the water leaves the nozzle at a high velocity and at atmospheric pressure, and two to six nozzles are distributed uniformly around the turbine circumference. The most commonly used impulse turbine design is the Pelton turbine.

Reaction turbines are generally used for installations where the head is relatively low and the flow is relatively high. The transfer of energy from the water to the turbine does not occur at atmospheric pressure, as it does in the Pelton turbine. The water changes pressure as it moves through the turbine and gives up its energy. Thus, reaction turbines are either encased to contain the water pressure or submerged in the water flow. Energy from the pressure drop is transferred to the turbine through both the fixed guide vanes and the rotating runner blades. The most common reaction turbine types are the Kaplan and Francis turbines.

The Kaplan turbine is a propeller-like water turbine with adjustable blades. The combination of adjustable propeller blade angle and adjustable wicket gates enables high efficiency to be achieved over a wider range of head and flow.

The Francis turbine uses a spiral-shaped inlet and guide vanes to direct the water tangentially to the turbine runner. This radial water flow transfers the energy to the runner vanes. Adjustable guide vanes allow higher efficiency over a wider range of head and flow.

The technologies associated with the turbines just described are well known and documented in many references. These technologies are not new, as evidenced by their dates of invention (Francis in 1848, Pelton in the 1870s, and Kaplan in 1913). Of course, the actual design and physics of hydraulic turbines are much more complex than the few sentences above convey. Much effort has been put into research and design to improve the efficiency and reliability of these basic designs, as well as to reduce adverse environmental impacts, such as the impacts on erosion and fish populations.

The general head-versus-flow relationships just described affect which type of turbine is selected for a particular site. This report focuses on pump storage hydro plants. Since the amount of energy stored is proportional to the volume of water and the head at which it is stored, in order to be economical, such plants generally require a reasonably high head so that a large amount of energy can be stored without a very large reservoir being required. In addition, since these plants must have relatively large power outputs to have a significant impact on power system operation, relatively high flow rates are required.

Figure 2-8 and Figure 2-9 show application ranges for the different hydro turbine types taken from two publicly available U.S. government references. Note that the axes for Figure 2-8 are head versus power, while those for Figure 2-9 are head versus flow. Both of these indicate the suitability of Francis turbines for applications that have a relatively high head (ranging from 100 to 2,000 feet) and that allow large turbines/generators (currently up to about 700 MW). Francis turbines can also be designed to be suitable for pumping operation. Hence, the vast majority of the large pumped storage plants built in the United States employ Francis turbines.

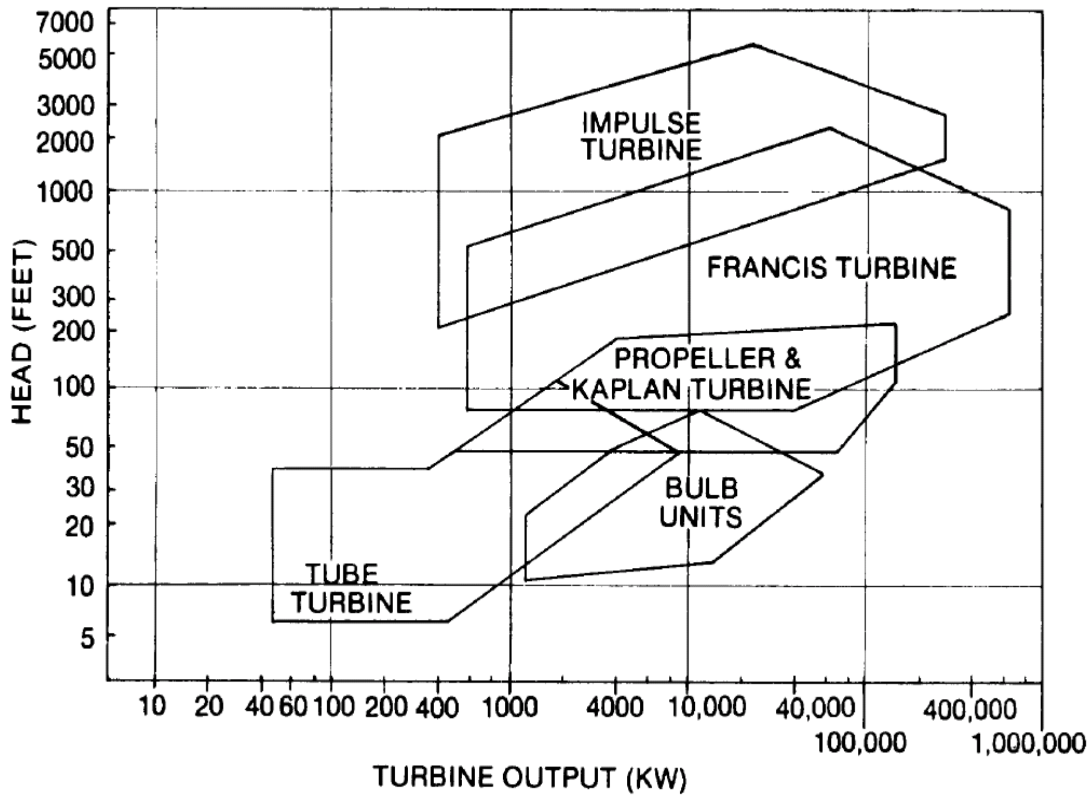


Figure 2-8 Hydro Turbine Application Ranges (From "Engineering and Design – Hydropower," U.S. Corp of Engineers Engineering Manual EM-1110-2-1701, December 1985)

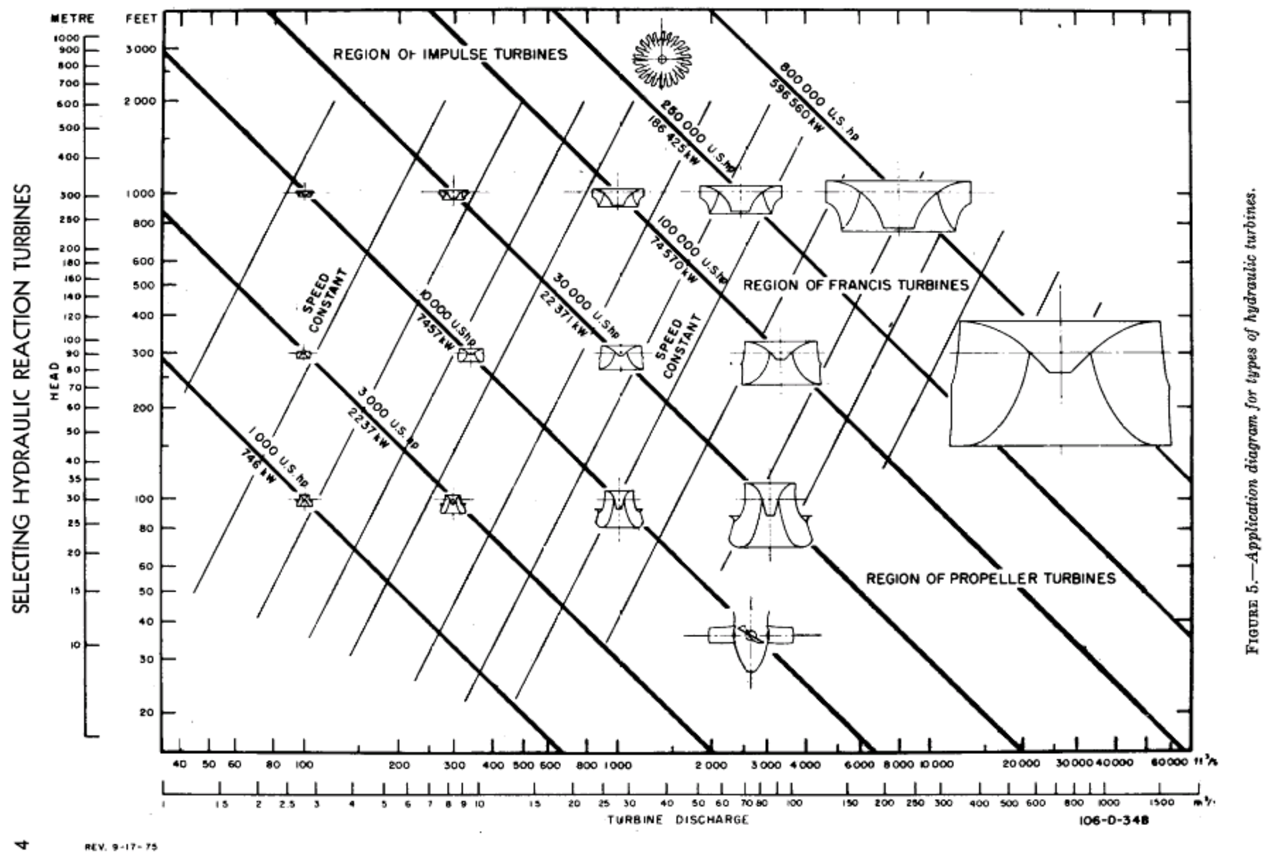


Figure 2-9 Hydro Turbine Application Ranges (From "Selecting Hydraulic Reaction Turbines," U.S. Bureau of Reclamation Engineering Monograph EM20, 1976)

Section
3

Hydro Turbine-Governor Simulation Models in PSS®E

3.1 Modeling Approach

This section provides a summary of the hydro governor models that can be found in commercial software packages that are commonly in use in North America as well as on other continents. Table 3-1 lists the models in the PSS®E software, while Table 3-2 lists the models in the PSLF software.

The models vary in their complexity, and hence, in their data requirements. In general, they differ in hydraulic system representation and can be grouped under "linear models" or "nonlinear models."

Linear models assume the following penstock/turbine transfer function:

$$\Delta p(s) / \Delta g(s) = (1 - T_W \times s) / (1 + T_W \times s/2) \qquad \text{(p.u.)}$$

where Δp and Δg are p.u. incremental changes in mechanical power and gate position around a steady-state operating point, respectively.

The water column time constant, T_W, is associated with the acceleration time for the water in the penstock between the turbine inlet and the forebay (or surge tank if present) and is given, approximately, by:

$$T_W = (L \times Q) / (g_v \times A \times H) \qquad \text{(s)}$$

where:

Q = water flow rate at initial loading level (m^3/s)

H = net hydraulic head at initial loading level (m)

L = centerline length of penstock conduit plus scroll case plus draft tube (m)

g_v = gravitational acceleration (m/s^2)

A = penstock cross-sectional area (m^2)

Table 3-1 Hydro Governor Models in the PSS®E Software

Model Name	Description
HYGOV	Standard hydro turbine governor model
HYGOV2	Linearized hydro turbine governor model
HYGOVM	Hydro turbine governor model with lumped parameters
HYGOVT	Hydro turbine governor model with traveling wave
HYGOVRU	Fourth order lead-lag hydro turbine governor model
IEEEG2	General-purpose linearized turbine governor model
IEEEG3	General-purpose linearized turbine governor model
PIDGOV	Hydro turbine governor model for plants with straightforward penstock configurations and three-term electro-hydraulic governors
TURCZT	General-purpose turbine governor model
TWDM1T	Hydro turbine governor model with tail water depression
TWDM2T	Hydro turbine governor model with proportional, integral, and derivative (PID) controller and tail water depression
WEHGOV	Woodward electro-hydraulic hydro turbine governor model
WPIDHY	Woodward PID hydro turbine governor model
WSHYDD	WECC double derivative hydro turbine governor model
WSHYPG	WECC type GP hydro turbine governor model
HYGOV4	Hydro turbine governor model

Table 3-2 Hydro Governor Models in the PSLF Software

Model Name	Description
G2WSCC	Double derivative hydro governor and turbine
GPWSCC	PID governor and turbine
HYG3	PID governor, double derivative governor, and turbine
HYGOV4	Hydro turbine and governor model for plants with straightforward penstock configurations and traditional dashpot-type hydraulic governors
HYGOV	Hydro turbine and governor model for plants with straightforward penstock configurations and electro-hydraulic governors that mimic the permanent/temporary droop characteristics of traditional dashpot-type hydraulic governors
HYGOVR	Fourth order lead-lag governor and hydro turbine
HYPID	Hydro turbine and governor model for plants with straightforward penstock configurations and proportional-integral-derivative governor. Includes capability to represent blade angle adjustment of Kaplan and diagonal flow turbines.
HYST1	Hydro turbine with Woodward electric-hydraulic PID governor, penstock, surge tank, and inlet tunnel
IEEEG3	IEEE hydro turbine and governor model for plants with straightforward penstock configurations and hydraulic-dashpot governors with optional deadband and nonlinear gain
PIDGOV	Hydro turbine and governor model for plants with straightforward penstock configurations and three-term electro-hydraulic governors (Woodward electronic)
W2301	Woodward 2301 governor and basic turbine model

Because the water flow rate (Q) at half load is about half its value at full load while the net hydraulic head (H) remains fairly constant, the water column time constant T_W varies significantly with the loading level. The linear models are used for small signal stability analysis and are valid only for the small deviations in system frequency and wicket gate position that are typical in hydro power stations in large power systems. These models also require that the user recalculate the value of T_W for each new initial loading level.

Nonlinear models, on the other hand, take into consideration this dependency of T_W with loading. The linearization of the nonlinear model of the penstock/turbine transfer function for small perturbations around a Q_0, H_0 operating point results in:

$$p / g = (1 - T_{W\,lin} \times s) / (1 + T_{W\,lin} \times s/2) \qquad \text{(p.u.)}$$

This is the same as given above for the linearized model, except that the water column time constant used in the above linearized equation is now defined as:

$$T_{W\,lin} = T_W \times Q_0 / H_0 \qquad \text{(s)}$$

where T_W in this equation is calculated as shown above but using the base flow and base head. Base flow is defined as the turbine flow rate when gates are fully open (g = 1 p.u.). The base hydraulic head is the net head available to the hydraulic turbine when the flow rate is the base flow. Q_0 and H_0 are per-unit quantities for the flow rate and net hydraulic head at the initial loading, respectively (Q_0 = initial flow / base flow and H_0 = initial head / base head).

By multiplying the water time constant T_W by Q_0 and $1/H_0$, the model automatically accounts for dynamic changes in its effective value; thus, the penstock/turbine model is valid for the full range of hydro turbine operations, from no load to maximum gate opening. It is used in transient stability analysis and is also valid for large speed deviations, and it can be used to simulate load rejection overspeed conditions if no relief valve or jet deflector action is expected.

More detailed models may also take into account other nonlinear effects, such as the nonlinear relationship between gate and flow (which can be significant in some turbines), the elasticity of the penstock conduit, and the compressibility of the working fluid. Other dynamics can also be included in the model, such as a more detailed modeling of the penstock dynamics and the effects of, for example, surge tanks.

Note that the models based on use of a water column time constant T_W as described above may not adequately represent all of the pertinent dynamics of plants with very long penstocks. The modeling of the penstock dynamics using T_W is valid only if the wave travelling time is much shorter than the water starting time. IEEE Standard 1207-2011, “IEEE Guide for the Application of Turbine Governing Systems for Hydroelectric Generating Units” states:

> “For very long penstocks, the wave travel time of the water column becomes significant, and the reflected pressure waves in the watercolumn cause the preceding treatment of water start time to no longer be valid. When the wave travel time

approaches 25% of the T_W, engineers should not rely on only the classic value of T_W, and the performance of the turbine governing system should be evaluated by considering the effects of both the water starting time and the wave travel time."[1]

While this standard is discussing hydro governor tuning, the comment is also valid for hydro modeling.

The wave travel time, also referred to at the elastic time T_e, is defined as L/a where L is the length of the penstock as defined above and a is the wave velocity. The wave velocity is a function of the properties of water and of the material the penstock is made of as well as the diameter and thickness of the penstock. Typical values of the water velocity are as follows[2]:

- 1220 m/s for steel conduit
- 1420 m/s for rock tunnels

It should also be noted that plants with long penstocks also often have surge tanks. If so, then the impacts of the surge tank must also be properly taken into account in the modeling of the plant.

3.2 Simulation Models in PSS®E

The commercial-grade Power System Simulator for Engineering (PSS®E) software includes models for hydro power plants that can be used for large signal time domain simulations for transient, mid-term, and long-term dynamics. The following turbine-governor and penstock dynamic models are part of the standard dynamic model library in PSS®E.

3.2.1 HYGOV Model

HYGOV represents a straightforward hydroelectric plant governor, with a simple hydraulic representation of the penstock with unrestricted head race and tail race, and no surge tank. The hydraulic and governor model is shown in Figure 3-1.

[1] "IEEE Guide for the Application of Turbine Governing Systems for Hydroelectric Generating Units," IEEE Std 1207-2011 (Revision to IEEE Std 1207-2004), June 20, 2011.
[2] Kundur, Prabha. Power System Stability and Control, McGraw-Hill Companies, Incorporated,1994.

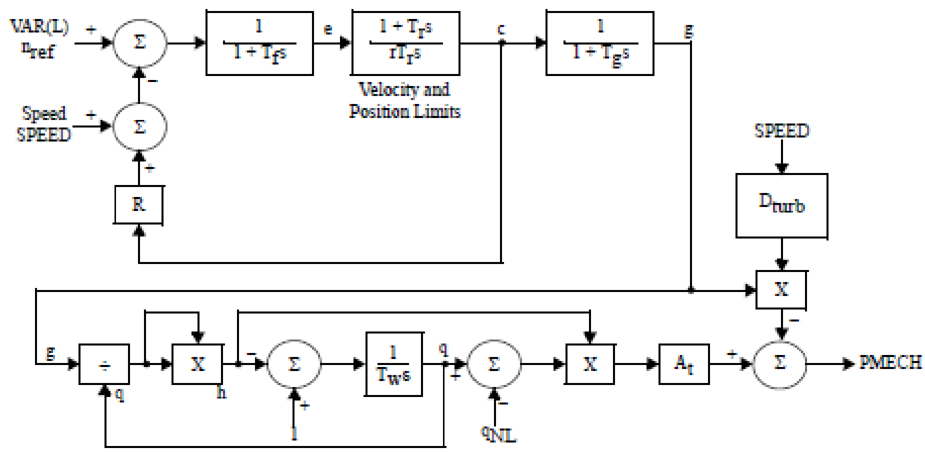


Figure 3-1 HYGOV Model Block Diagram for Turbine-Governor/Penstock Dynamics

In the figure,

R = permanent droop (p.u. on generator (megavolt ampere [MVA] rating)

r = transient droop (p.u. on generator MVA rating)

T_r = governor time constant (s)

T_f = filter time constant (s)

T_g = servo time constant (s)

VELM = gate velocity limit (p.u./s)

GMAX = maximum gate limit (p.u.)

GMIN = minimum gate limit (p.u.)

T_W = water time constant (s)

A_t = turbine gain (p.u.)

D_{turb} = turbine mechanical damping (p.u. on generator MVA rating)

q_{NL} = no-load water flow rate that accounts for the fixed losses in the turbine (p.u. of base water flow)

Linearization of the penstock/turbine transfer function for small perturbations around a Q_0, H_0 operating point results in:

$$p/g = (1 - T_{W\ lin} \times s)/(1 + T_{W\ lin} \times s / 2)$$

where:

$$T_{W\ lin} = T_W \times Q_0 / H_0$$

T_W is calculated by using the base flow rate and base net hydraulic head; and thus, is independent of the initial loading level. By multiplying the water time constant T_W by Q_0 and $1/H_0$, the model automatically accounts for dynamic changes in its effective value.

The penstock/turbine model is valid for the full range of hydro turbine operations, from speeds at no load to the maximum gate opening. This governor model is valid for dashpot-type mechanical governors (e.g., Woodward, English Electric) and for dashpot-equivalent electrohydraulic governors (e.g., ASEA). No acceleration governing (derivative control action) term is included because this is used only in specialized situations in most interconnected power systems.

The permanent droop, R, and temporary droop, r, are specified in per unit on a base equal to the generator three-phase MVA rating. The velocity limit, VELM, is the reciprocal of the time taken for the wicket gates to move from fully open to fully closed. The maximum gate limit, GMAX, is equal to the gate limit setting as established by the operator at the governor console; it cannot exceed 1 p.u. The minimum gate position is normally zero. The no-load flow rate, q_{NL}, is the flow rate required to maintain the rated speed when the unit is off line; q_{NL} is expressed in p.u. of the base flow rate.

The turbine gain, A_t, is given by:

$$1 / (g_{FL} - g_{NL})$$

where:

g_{FL} = full load gate opening (p.u.) ($0 < g_{FL} \leq 1$)

g_{NL} = no load gate opening (p.u.) ($0 < g_{NL} < 1$)

3.2.2 HYGOV2 Model

The hydro turbine-governor HYGOV2 model has the same basic permanent and transient droop elements as the HYGOV model but adds a slightly different representation of the time lags within the governor hydraulic servo system and of the shaft speed deviation signal filtering (Figure 3-2).

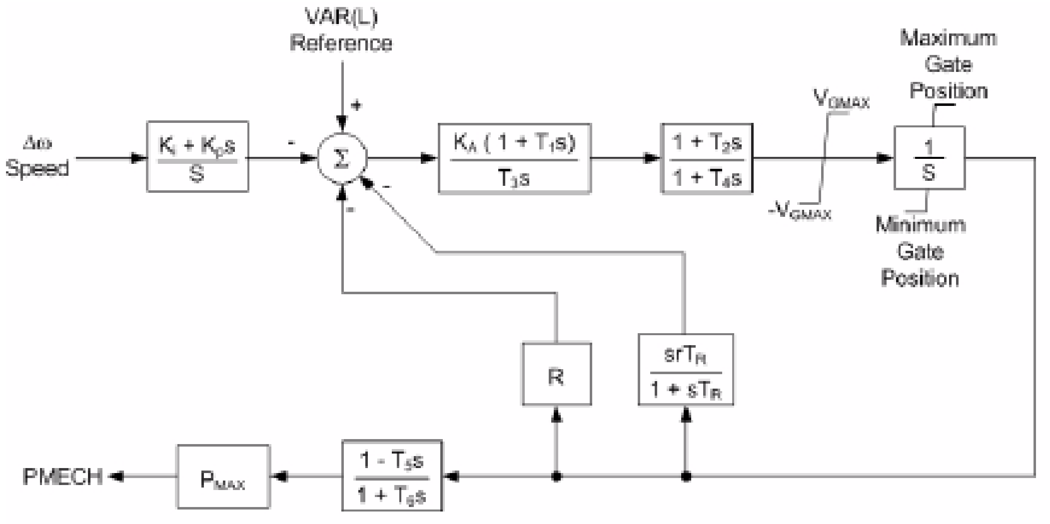


Figure 3-2 HYGOV2 Model Block Diagram for Turbine-Governor/Penstock Dynamics

The penstock/turbine-governor model of HYGOV2 is highly simplified and is valid only for small deviations of the gate position from its initial condition. Unlike HYGOV, HYGOV2 requires the user to recalculate the value of the water column time constants for each new initial loading level. The water column time constants, T_5 and T_6, of HYGOV2 are related to the water inertia time constant T_W by:

$$T_5 = P_0 T_W \text{ (s)}$$

and

$$T_6 = P_0 T_W / 2 \text{ (s)}$$

where:

P_0 = the initial power in per unit of rated power (power developed at the base flow rate and net hydraulic head as defined above).

HYGOV2 was developed for a specific hydraulic plant and should not be used except in appropriate special situations. For the great majority of situations, HYGOV is the preferred choice.

3.2.3 HYGOVM Model

In hydro power plant layouts where a long supply penstock conduit is required, it is fairly common practice to use a surge tank. The purpose of the surge tank is to provide a degree of hydraulic isolation to the turbine from the hydraulic head deviations generated by hydraulic transients in the longest portion of the penstock. Many surge tanks also include an orifice where head loss serves to dissipate the energy of hydraulic oscillations generated by changes in gate position. The orifice introduces a damping effect. The lumped parameters hydraulic system model in HYGOVM is designed to allow detailed simulation of the representation of the surge tank system:

- Penstock dynamics
- Surge tank chamber dynamics
- Tunnel dynamics
- Penstock, tunnel, and surge tank chamber orifice losses
- Surge tank chamber level beyond maximum or minimum alarm

The HYGOVT model is similar to the HYGOVM model, but it uses a traveling wave calculation for the tunnel and penstock dynamics. The HYGOVM and HYGOVT models should be used for dynamic analyses of hydro plants when the time range of interest is comparable to the surge tank natural period, including long-term stability analyses, surge tank chamber dynamics analyses, and load rejection analyses involving relief valve or jet deflector action.

For shorter time periods, the simpler HYGOV model can be used. The HYGOV model assumes an infinite surge tank and is appropriate unless relief valve or jet deflector action is expected.

The surge tank natural period is defined as:

surge tank natural period = (SCHARE x TUNL/A) / gravitational acceleration

Penstock dynamics are largely determined by the upper loop in the block diagram of the HYGOVM model shown in Figure 3-3.

The loop gain is proportional to the inverse of the square of gate position and thereby increases significantly for small openings. Under load rejection conditions, near total gate closure, the loop effective time constant will tend to approach zero. The model cannot handle low time constants without incurring numerical instability. It deals with this problem by assuming an algebraic solution (i.e., an instantaneous response, just before numerical instability would occur). This change in model response can be visualized by an instantaneous drop in the turbine's hydraulic head to values close to the head at the surge tank chamber opening. At the time the algebraic solution is applied, power and flows at the penstock are negligible and would not affect governor or surge tank chamber studies.

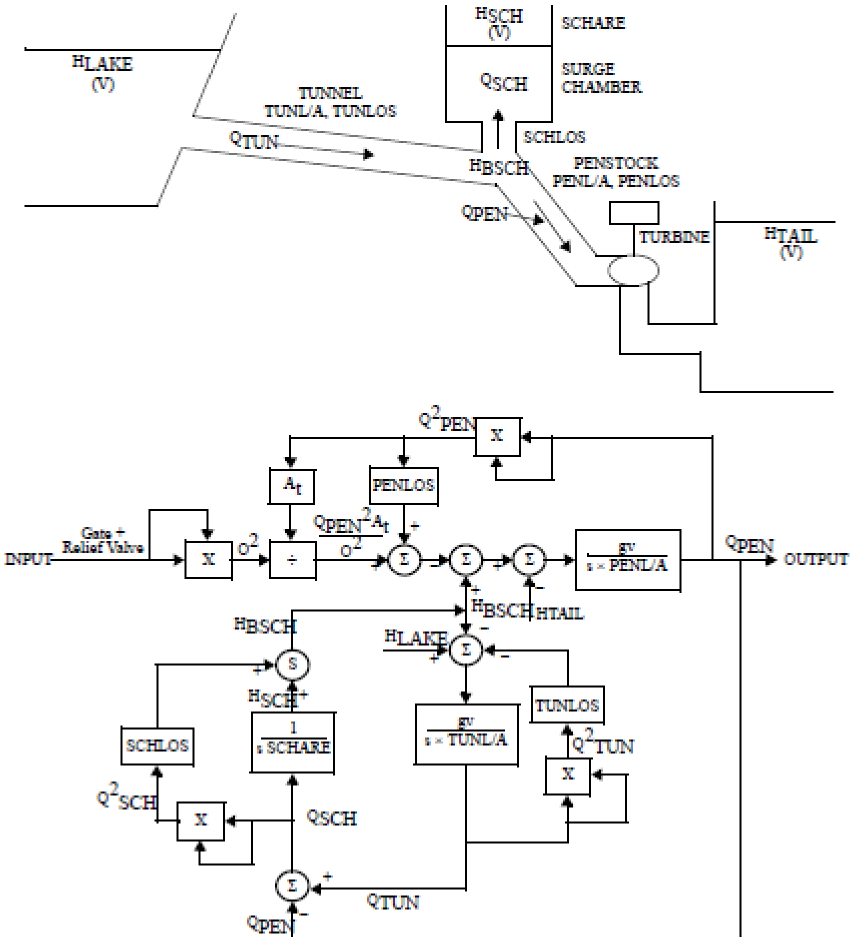
The turbine-governor system used in the HYGOVM model is shown in Figure 3-4. It is based on the HYGOV turbine-governor representation with these additional features:

- *Separate maximum opening and closing gate rate limits*. The maximum gate closing rate (MXGTCR) is usually a compromise between constraints due to maximum scroll case head, surge tank overflows, and unit overspeed under load rejection. A representative value for this parameter is 0.125 p.u./s. The maximum gate opening rate (MXGTOR) determines the minimum surge chamber levels when accepting load. A value of 0.1 p.u./s is representative.

- *Buffered opening and closing rates when gate opening is near full closure*. Buffering the gate closure may produce a reduction in overpressures under load rejection. This feature will reduce impact loadings on the gate linkage and limit the magnitude of the pressure pulsations that occur while the gates are fully closed during the decay of load rejection overspeed. A representative value for the maximum buffered closing gate rate (MXBGCR) is –0.05 p.u./s, and 0.15 p.u. for the buffer limit (BUFLIM). The maximum buffered opening rate (MXBGOR) is normally equal to MXGTOR.

- *Pressure regulator (relief valve) simulation*. This regulator is a bypass, generally attached to the turbine casing. It is operated directly from the governor or the gate mechanism of the turbine. The amount of water bypassed is sufficient to keep the total discharge through the penstock fairly constant and thereby control the rise in pressure. The maximum relief valve opening (RVLMAX) can be set equal to GMAX. For the water-wasting type, the maximum relief valve closing rate (RVLVCR) should be set to 0.0 p.u./s; for the water-saving type, a representative value for RVLVCR is –0.0143 p.u./s.

- *Jet deflector simulation*. Plants with long penstocks and impulse turbines (Pelton) are not allowed to have rapid reductions in water velocity because of the pressure rise that would occur. To minimize the rise in pressure that follows a sudden load rejection, a governor-controlled jet deflector is normally placed between the needle nozzle and the runner. The governor moves this deflector rapidly into the jet, cutting off the load. Typical values for maximum jet deflector opening and closing rates (MXJDOR and MXJDCR) are 0.5 p.u./s and –0.5 p.u./s, respectively.

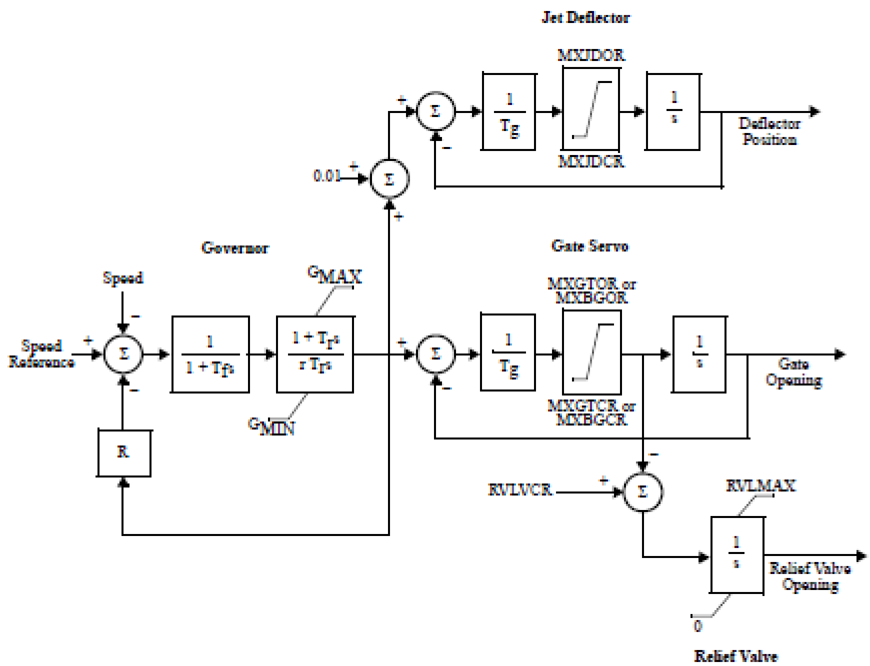


LEGEND:

gv	Gravitational acceleration	A_t	Turbine flow gain
TUNL/A	Summation of length/cross section of tunnel	O	Gate + relief valve opening
SCHARE	Surge chamber cross section	HSCH	Water level in surge chamber
PENLOS	Penstock head loss coefficient	QPEN	Penstock flow
TUNLOS	Tunnel head loss coefficient	QTUN	Tunnel flow
FSCH	Surge chamber orifice head loss coefficient	QSCH	Surge chamber flow
PENL/A	Summation of length/cross section of penstock, scroll case and draft tube		

Hydro Turbine Governor Lumped Parameter Model

Figure 3-3 HYGOVM Model for Penstock Dynamics



LEGEND:

R	Permanent droop	MXBGCR	Maximum buffered gate closing rate
r	Temporary droop	GMAX	Maximum gate limit
T_r	Governor time constant	GMIN	Minimum gate limit
T_f	Filter time constant	RVLVCR	Relief valve closing rate
T_g	Servo time constant	RVLMAX	Maximum relief valve limit
MXGTOR	Maximum gate opening rate	MXJDOR	Maximum jet deflector opening rate
MXGTCR	Maximum gate closing rate	MXJDCR	Maximum jet deflector closing rate
MXBGOR	Maximum buffered gate opening rate		

Figure 3-4 HYGOVM and HYGOVT Model Block Diagram for Turbine-Governor Dynamics

Turbine characteristics in HYGOVM are defined based on these rated conditions:

Rated power, P_{rated} (MW)

Rated flow, Q_{Rated} (m^3/s or ft^3/s)

Rated head, H_{Rated} (m or ft)

Gate opening at rated operating point, G_{Rated} (p.u.)

Flow at no load, $Q_{No\ load}$ (p.u. of rated water flow rate)

The following parameters are calculated by the model:

K_t (turbine power gain) = P_{rated} / [($Q_{Rated} - Q_{No\ load}$) × H_{Rated} × MVABase] (p.u.)

T_{fg} (turbine flow gain) = Q_{Rated} / [(G_{Rated} × $\sqrt{(H_{Rated})}$] (p.u.)

Turbine power is a function of turbine flow and turbine head; and thus, a function of penstock flow, gate position, and relief valve or jet deflector position.

For turbines with a relief valve:

Turbine flow = ($Q_{penstock}$ × gate opening) / (gate opening + relief valve opening)

Turbine head = $(Q_{penstock})^2$ × A_t / (gate opening + relief valve opening)^2

For turbines with a jet deflector:

Turbine flow = $Q_{penstock}$ × MIN (1., jet position/gate opening) (m^3/s or ft^3/s)

Turbine head = $Q_{penstock}^2$ A_t / (gate opening)^2 (m or ft)

For turbines with neither a relief valve nor a jet deflector:

Turbine flow = $Q_{penstock}$ (m^3/s or ft^3/s)

Turbine head = $Q_{penstock}^2$ A_t / (gate opening)^2 (m or ft)

Turbine power and damping are as follows:

Turbine power = K_t × turbine head × (turbine flow – turbine no-load flow) – damping

Turbine damping = DAMP × pu speed deviation × MIN (jet position, gate position)

where:

DAMP = DAMP1 for overspeeds under RPM1,

= DAMP2 for overspeeds above RPM2, and

= linearly interpolated for overspeeds between RPM1 and RPM2.

3.2.4 HYGOVT Model

In this model, a traveling-wave solution is applied to the penstock and tunnel dynamics. The traveling wave model for the penstock and tunnel dynamics is shown in Figure 3-5. The penstock and tunnel are divided into 9 to 19 segments, and the characteristics solution method is applied to the resulting time-space lattice. Boundary conditions and head losses are fully recognized. For accurate results, the simulation time step should be no larger than:

PENLGTH/(9 x PENSPD) (s)

where PENLGTH is the penstock conduit length and PENSPD is the penstock wave velocity.

Maximum accuracy is attained when simulation time step is equal to, or a submultiple of

PENLGTH/(19 x PENSPD) (s)

Conduit wave velocity alone, when rigid walls are assumed and water compressibility is accounted for, is 1,420 m/s (4,659 ft/s). This wave velocity is the maximum that can be physically attained. Actual conduits do not have rigid walls. A representative value for penstock conduits is 1,100 m/s (3,609 ft/s).

For this model, the governor and turbine models are the same as in the HYGOVM model (Figure 3-4). The decision to use the inelastic (HYGOVM) model or elastic (HYGOVT) model relies on the hydraulic system characteristics and the study scope. Because of time-step constraints, traveling-wave simulation turnover may be penalized by the need to use a smaller time step than would otherwise be required with the inelastic model. However, some error is involved with the use of an inelastic model. This error can be quantified by the difference between the elastic and the inelastic frequency response of the hydraulic head/flow rate transfer functions. This difference, in p.u. of the elastic case, is approximately:

$$-(T_p^2 \times s^2)/3$$

where T_p is the penstock wave travel time constant (PENLGTH/PENSPD) in seconds and s is the Laplace operator. The time constant T_p is typically 0.5 second but can be as high as 1.5 seconds for long penstocks. For normal governor action, the speed loop crossover frequency (i.e., the dominant mode) occurs at about $1/(2T_W)$ rad per second. With the water time constant T_W being typically 1 to 2 seconds, s is on the order of 0.25 to 0.5 rad per second. The difference between elastic and inelastic response is usually negligible, unless very long penstocks are studied. A critical case run using both model assumptions could prove to be the easiest way to assess this difference.

There are times when traveling wave analysis is essential. Overpressures due to load rejection are critical just before or at gate closure time; the ensuing pressure pulsations occur after the gate is totally closed. A closed or an almost-closed gate results in infinitely small penstock time constants and infinitely large values for s.

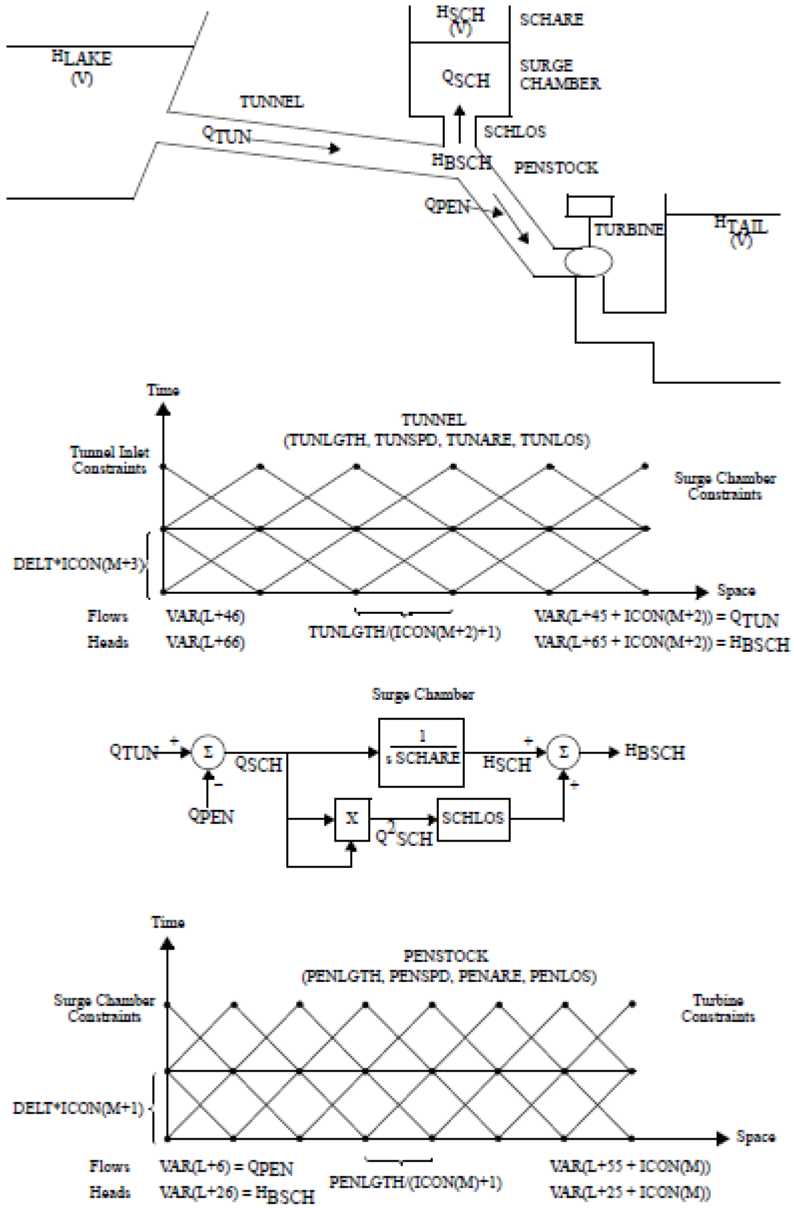


Figure 3-5 HYGOVT Traveling-Wave Model for Penstock Dynamics

3.2.5 IEEEG2 Model

This is a general-purpose linearized model for representing a hydro turbine-governor and penstock dynamics (Figure 3-6). Its use is generally not recommended, since the parameters are valid only at the load for which they are calculated. Thus, use of a dynamics database containing such models with load flow cases having different dispatches on the units may yield inaccurate results, unless the parameters are updated to match the revised dispatch.

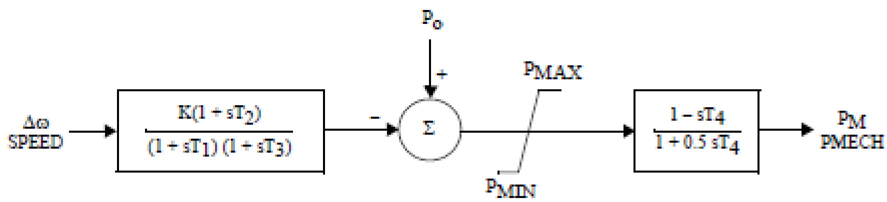


Figure 3-6 IEEEG2 Model Block Diagram for Turbine-Governor/Penstock Dynamics

In this model,

K = permanent governor gain (1/R) (p.u. on generator MVA rating)

T_1 = compensator time constant (s)

T_2 = compensator time constant (s)

T_3 = governor time constant (s)

T_4 = water time constant (s)

P_{MAX} = maximum gate position (p.u. on generator MVA rating)

P_{MIN} = minimum gate position (p.u. on generator MVA rating)

3.2.6 IEEEG3 Model

This is a general-purpose model for representing a hydro turbine-governor and penstock dynamics (Figure 3-7). It includes a more complex representation of the governor controls than does IEEEG2. It also uses a linearized model of the penstock dynamics, albeit one that is a bit more complex. Its use is generally not recommended, since the parameters are valid only at the load for which they are calculated. Thus, use of a dynamics database containing such models with load flow cases having different dispatches on the hydro-turbine-driven generating units may yield inaccurate results, unless the parameters are updated to match the revised dispatch.

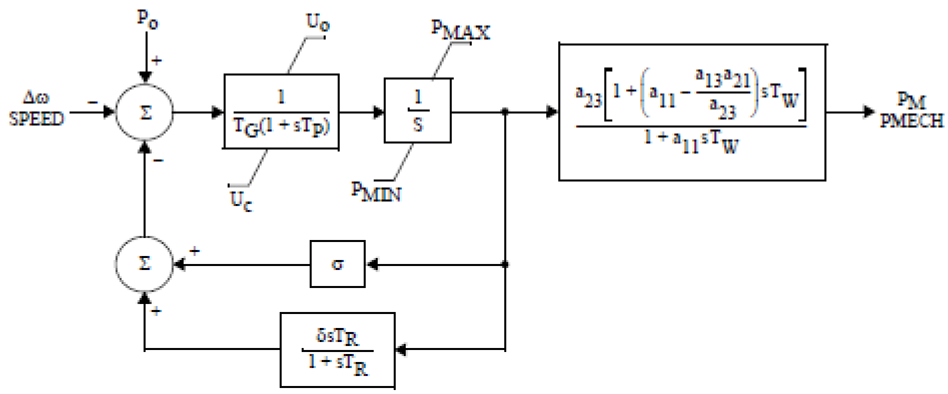


Figure 3-7 IEEG3 Model Block Diagram for Turbine-Governor/Penstock Dynamics

In this model,

T_G = gate servomotor time constant (s)

T_P = pilot value time constant (s)

U_O = opening gate rate limit (p.u./s)

U_C = closing gate rate limit (p.u./s)

P_{MAX} = maximum gate position (p.u. on generator MVA rating)

P_{MIN} = minimum gate position (p.u. on generator MVA rating)

σ = permanent speed droop coefficient (p.u. on generator MVA rating)

δ = transient speed droop coefficient (p.u. on generator MVA rating)

T_R = governor time constant (s)

T_W = water starting time constant (s)

a_{11}, a_{13}, a_{21}, a_{23} = penstock coefficients

3.2.7 PIDGOV Model

The PIDGOV hydro turbine governor model represents hydro power plants with straightforward penstock configurations and three term electro-hydraulic governors (i.e., Woodard electronic) (Figure 3-8). This model uses a simplified turbine-governor and penstock model that does not account for the variation of the water inertia effect with the gate opening. This model can be made to correspond to other models by using the classical turbine-governor/penstock model by setting A_{tw} (factor that multiplies the water inertia time constant) to unity.

The feedback signal used by the governor can either be the gate position or the electrical power, and it can be selected by setting the feedback flag to 1 for gate position or to 0 for electrical power. The input to this model is the shaft speed deviation, and the outputs are turbine gate position and mechanical power.

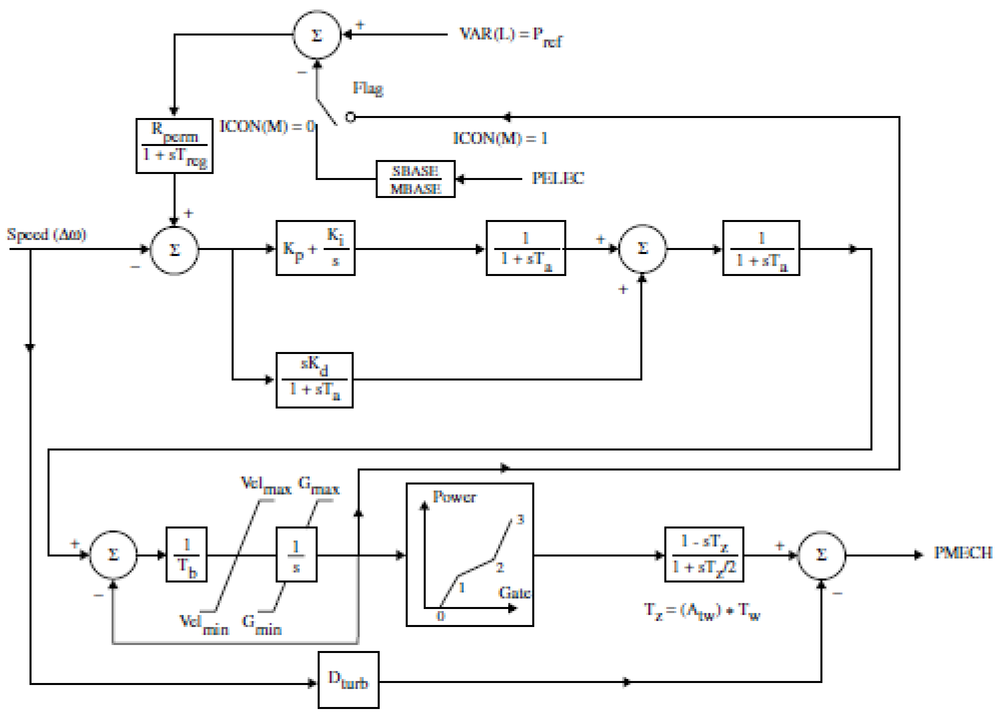


Figure 3-8 PIDGOV Model Block Diagram for Turbine-Governor and Penstock Dynamics

In this model,

R_{perm} = permanent droop (p.u. on generator MVA rating)

T_{reg} = speed probe time constant (s)

K_p = controller proportional gain (p.u.)

K_i = controller integral gain (p.u./s)

K_d = controller derivative gain (p.u./s)

T_a = controller time constant (s)

T_b = wicket gate servo time constant (s)

D_{turb} = turbine damping factor (p.u.)

G_0 = gate position at no load (p.u.)

G_1 = gate intermediate position (p.u.)

P_1 = power at gate position G_1 (p.u. on generator MVA rating)

G_{max} = maximum gate opening (p.u.)

G_{min} = minimum gate opening (p.u.)

T_W = water time constant (s)

Vel_{max} = maximum gate opening velocity (p.u./s)

Vel_{min} = minimum gate opening velocity (p.u./s)

3.2.8 TURCZT Model

This is a general-purpose hydro and thermal turbine-governor model (Figure 3-9). A hydro turbine or steam turbine dynamic model can be selected by setting a flag to 1 for a steam turbine and to 0 for a hydro turbine. Penstock dynamic is not included in the model. The model was developed for a specific user and it is not recommended for general use.

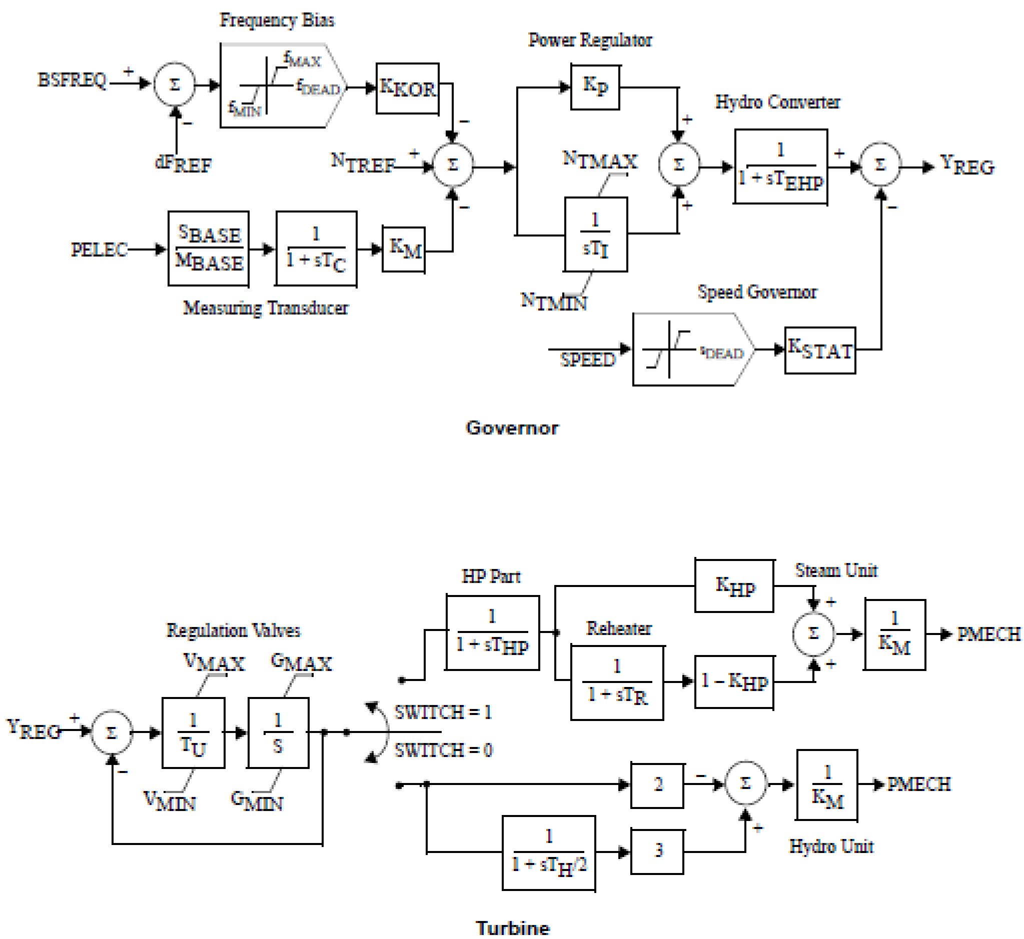
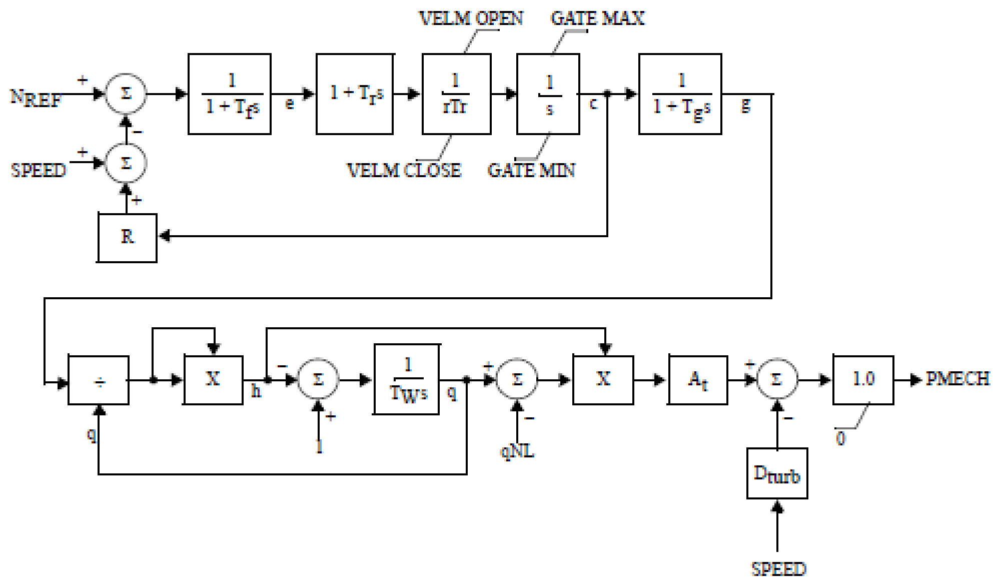


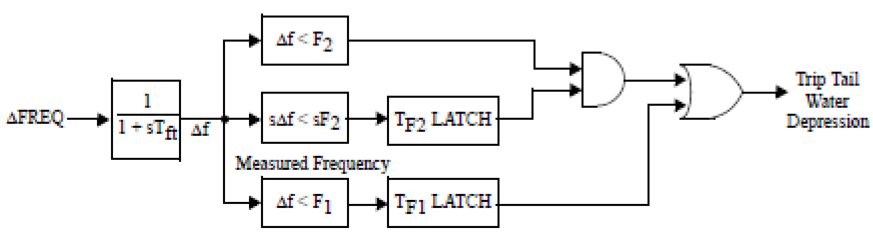
Figure 3-9 TURCZT Model Block Diagram for Turbine-Governor Dynamics

3.2.9 TWDM1T Model

The hydro turbine-governor model TWDM1T has the same basic permanent and transient droop elements as the HYGOV model, but it adds a representation for a tail water depression protection system (Figure 3-10).



Tail Water Depression Model 1



Tail Water Depression Trip Model

Figure 3-10 TWDM1T Model Block Diagram for Turbine-Governor/Penstock Dynamics

In this model,

R = permanent droop (p.u. on generator MVA rating)

r = transient droop (p.u. on generator MVA rating)

T_r = governor time constant (s)

T_f = filter time constant (s)

T_g = servo time constant (s)

VELMX = open gate velocity limit (p.u./s)

VELMN = close gate velocity limit (p.u./s)

GMAX = maximum gate limit (p.u.)

GMIN = minimum gate limit (p.u.)

T_W = water time constant (s)

A_t = turbine gain (p.u.)

Dturb = turbine damping factor (p.u.)

q_{NL} = flow rate at no load (p.u.)

F_1 = frequency deviation (p.u.)

T_{F1} = time delay (s)

F_2 = frequency deviation (p.u.)

sF2 = frequency (p.u.)

T_{F2} = time delay (p.u.)

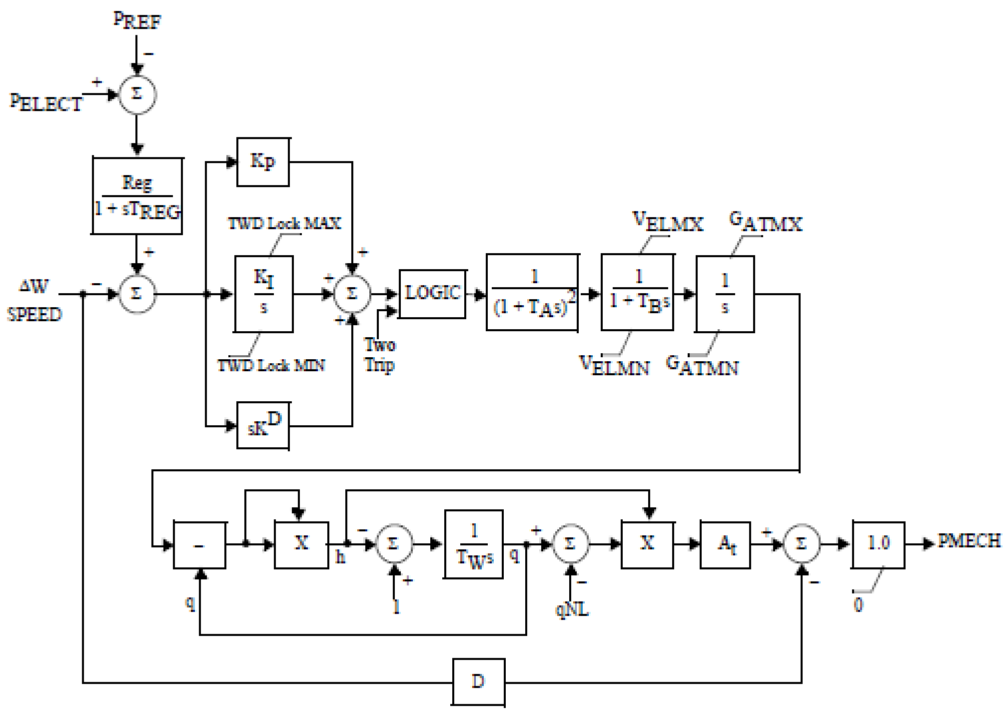
GMXRT = rate at which GMAX changes when T_{WD} is tripped (p.u./s)

N_{REF} = set point frequency deviation (p.u.)

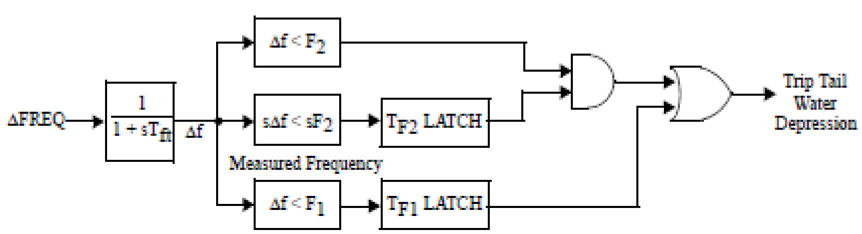
T_{ft} = frequency filter time constant (s)

3.2.10 TWDM2T Model

The hydro turbine-governor model TWDM2T has the same basic turbine/penstock elements as the HYGOV model but it adds a representation for a tail water depression protection system and uses a governor proportional-integral-derivative (PID) controller (Figure 3-11).



Tail Water Depression Model 2



Tail Water Depression Trip Model

Figure 3-11 TWDM2T Model Block Diagram for Turbine-Governor/Penstock Dynamics

In this model,

Reg = permanent droop (p.u. on generator MVA rating)

K_P = controller proportional gain (p.u.)

K_I = controller integral gain (p.u./s)

K_D = controller derivative gain (p.u.-s)

T_A = controller time constant (s)

T_B = controller time constant (s)

VELMX = open gate velocity limit (p.u./s)

VELMN = close gate velocity limit (p.u./s)

GATMX = maximum gate limit (p.u.)

GATMN = minimum gate limit (p.u.)

T_W = water time constant (s)

A_t = turbine gain (p.u.)

q_{NL} = flow rate at no load (p.u.)

D_{turb} = turbine damping factor (p.u.)

F_1 = frequency deviation (p.u.)

T_{F1} = time delay (s)

F_2 = frequency deviation (p.u.)

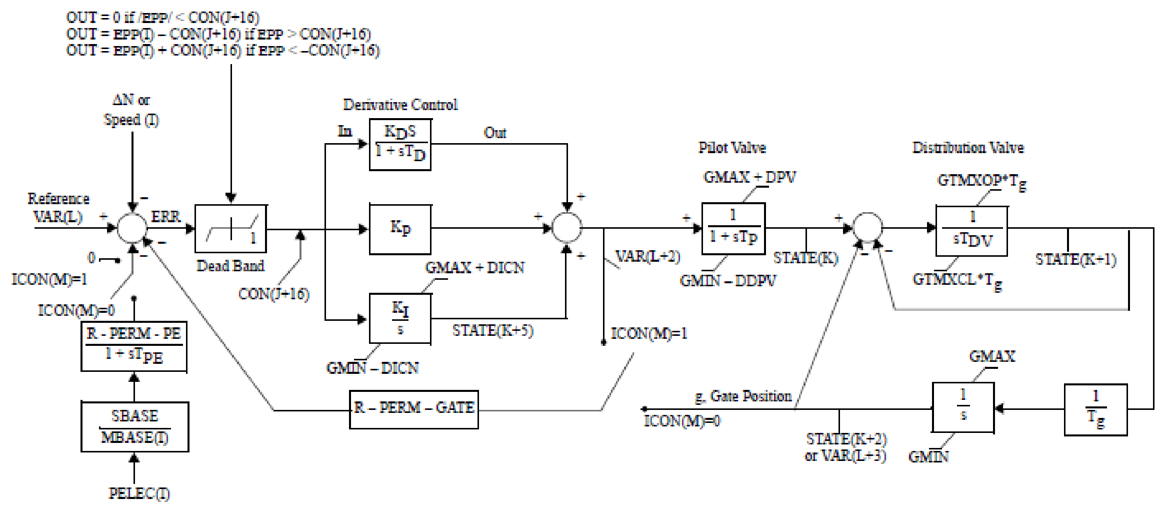
sF2 = frequency (p.u.)

T_{F2} = time delay (s) P_{REF} = power reference (p.u. on generator MVA rating)

T_{ft} = frequency filter time constant (s)

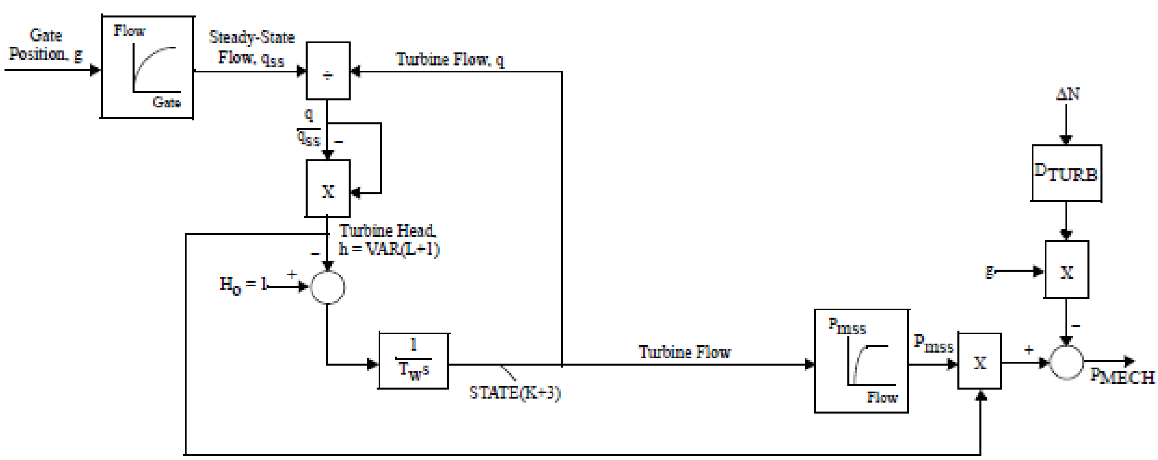
3.2.11 WEHGOV Model

WEHGOV is a model of a Woodward Electronic hydro-governor with PID control (Figures 3-12 and 3-13). The turbine is represented by a nonlinear model for the penstock dynamics in a fashion similar to that used for HYGOV, but the model includes look-up tables to allow the user to represent nonlinearities in flow rate versus gate position and in mechanical power versus flow rate during steady-state operation. The model allows for the use of two feedback signals for droop: (1) electrical power and gate position and (2) PID output.



Governor and Hydraulic Actuators

Figure 3-12 WEHGOV Model Block Diagram for Governor Dynamics



Turbine Dynamics

Figure 3-13 WEHGOV Model Block Diagram for Turbine/Penstock Dynamics

PID Controller

The derivative controller has a time constant to limit the derivative characteristic beyond a breakdown frequency to avoid amplification of high-frequency noise. This time constant is labeled T_D, and its value is typically 0.10 second. The PID controller also has a limiter on the integral control to prevent windup when the gates are at their limits. The gate position limits are set in GMAX for maximum and GMIN for minimum. For the integral controller, there is another variable called DICN, which allows the integral controller to advance beyond the values for the gate limits. The maximum limit for the integral controller is:

GMAX + DICN (p.u.)

The minimum limit is:

GMIN – DICN (p.u.)

The value for DICN ranges from 0% to 10%, and is set with the field tuning for the governor.

Pilot Valve

The output signal of the PID controller is fed into the pilot valve. The pilot valve also has a set of limits that are similar to those for the integral controller. The maximum limit for the pilot valve output is:

GMAX + DPV (p.u.)

The minimum limit is:

GMIN – DPV (p.u.)

The value for DPV is typically about 2% to ensure that the gate can be fully opened or closed.

Distribution Valve

The output signal of the pilot valve is fed into the distribution valve. The limits of the distribution valve define the maximum rates to open or close the gates. These two rate limits are:

GTMXOP, maximum gate opening rate (p.u./s)

GTMXCL, maximum gate closing rate (p.u./s)

The values for both parameters are in p.u. gate position per second. Note that the value for GTMXCL must be less than 0.

Turbine Model

The model for the penstock hydraulics is similar to that for HYGOV. However, the turbine model includes two look-up tables to account for steady-state nonlinearities in the model. The first table represents the water flow rate through the turbine as a function of gate position. The second table represents p.u. mechanical power on the generator MVA rating as a function of water flow rate.

3.2.12 WPIDHY Model

This is a hydro turbine-governor/penstock model that includes governor controls representing a Woodward PID hydro governor (Figure 3-14). The model includes a nonlinear gate/power relationship and a linearized turbine/penstock model.

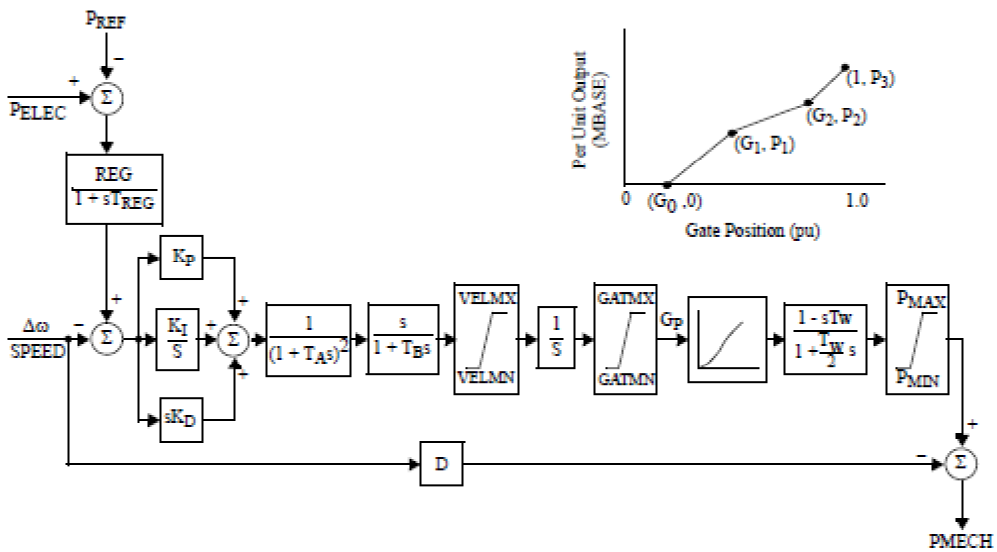


Figure 3-14 WPIDHY Model Block Diagram for Turbine-Governor/Penstock Dynamics

In this model,

REG = permanent droop (p.u. on generator MVA base)

T_{REG} = governor time constant (s)

K_P = controller proportional gain (p.u.)

K_I = controller integral gain (p.u./s)

K_D = controller derivative gain (p.u./s)

T_A = controller time constant (s)

T_B = controller time constant (s)

VELMX = open gate velocity limit (p.u./s)

VELMN = close gate velocity limit (p.u./s)

GATMX = maximum gate limit (p.u.)

GATMN = minimum gate limit (p.u.)

T_W = water time constant (s)

P_{MAX} = maximum gate position (p.u.)

P_{MIN} = minimum gate position (p.u.)

G_0 = gate position at no load (p.u.)

G_1 = first gate intermediate position (p.u.)

P_1 = power at gate position G_1 (p.u. on generator MVA rating)

G_2 = second gate intermediate position (p.u.)

P_2 = power at gate position G_2 (p.u. on generator MVA rating)

P_3 = power at fully open gate (p.u. on generator MVA rating)

3.2.13 WSHYDD Model

This is the WECC double-derivative hydro turbine-governor model (Figure 3-15). This model includes two deadbands. One "intentional" deadband is implemented at the input. It has a "bowtie" hysteresis form when db_1 is set equal to err, and it has no hysteresis when err is set to 0. The second deadband in the gate controls loop is "unintentional," which describes mechanical backlash with a hysteresis form. When db_2 is set to 0, the mechanical backlash is ignored. This dynamic model also includes a nonlinear gate/power relationship and a linearized turbine/penstock model. The governor's permanent droop (R) is entered in p.u. on the turbine MW rating T_{rate}.

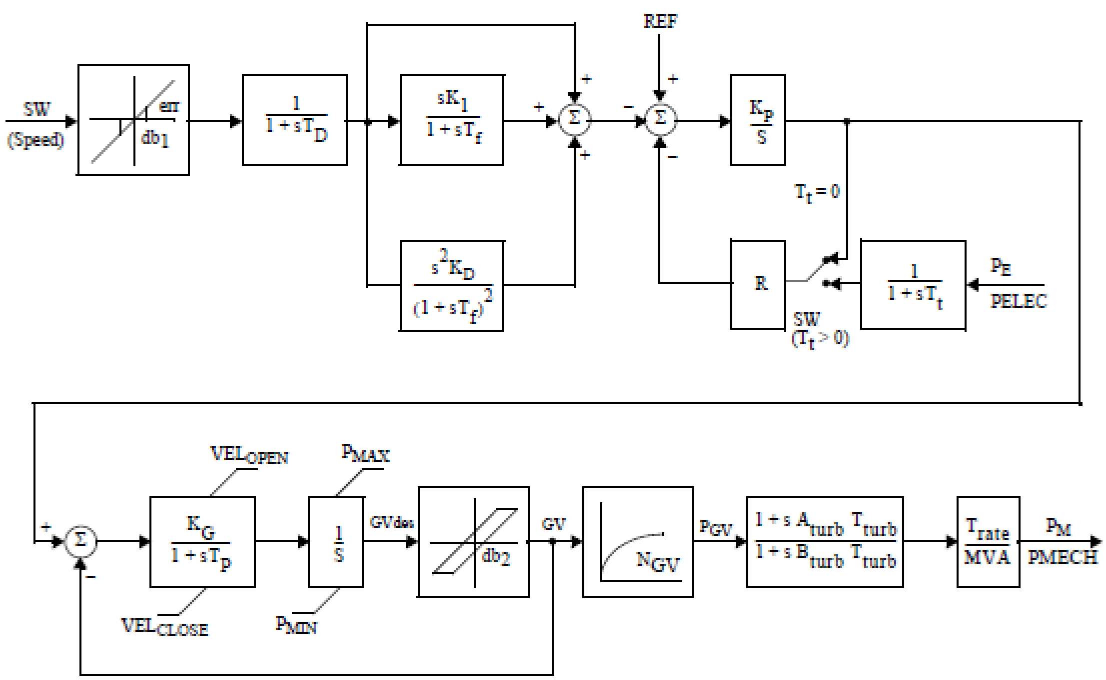


Figure 3-15 WSHYDD Model Block Diagram for Turbine-Governor/Penstock Dynamics

In this model,

db_1 = deadband width (p.u.)

err = deadband hysteresis (p.u.)

T_D = input filter time constant (s)

K_1 = derivative gain (p.u.)

T_f = derivative time constant (s)

K_D = double derivative gain (p.u.)

K_P = integral gain (p.u.)

R = droop (p.u. on Trate)

T_t = power feedback time constant (s)

K_G = gate servo gain (p.u.)

T_P = gate servo time constant (s)

VEL_{OPEN} = maximum gate opening rate (p.u./s)

VEL_{CLOSE} = maximum gate closing rate (p.u./s)

P_{MAX} = maximum gate opening (p.u.)

P_{MIN} = minimum gate opening (p.u.)

db_2 = deadband (p.u.)

GV_1 = coordinate of power-gate look-up table (p.u. gate)

PGV_1 = coordinate of power-gate look-up table (p.u. power)

GV_2 = coordinate of power-gate look-up table (p.u. gate)

PGV_2 = coordinate of power-gate look-up table (p.u. power)

GV_3 = coordinate of power-gate look-up table (p.u. gate)

PGV_3 = coordinate of power-gate look-up table (p.u. power)

GV_4 = coordinate of power-gate look-up table (p.u. gate)

PGV_4 = coordinate of power-gate look-up table (p.u. power)

GV_5 = coordinate of power-gate look-up table (p.u. gate)

PGV_5 = coordinate of power-gate look-up table (p.u. power)

A_{turb} = turbine lead time constant multiplier

B_{turb} (>0) = turbine lag time constant multiplier

T_{turb} (>0) = turbine time constant (s)

T_{rate} = turbine rating (MW)

3.2.14 WSHYPG Model

This is the WECC GP hydro turbine-governor model with a PID controller (Figure 3-16). The penstock dynamics are similar to those of the WECC WSHYDD hydro turbine-governor model.

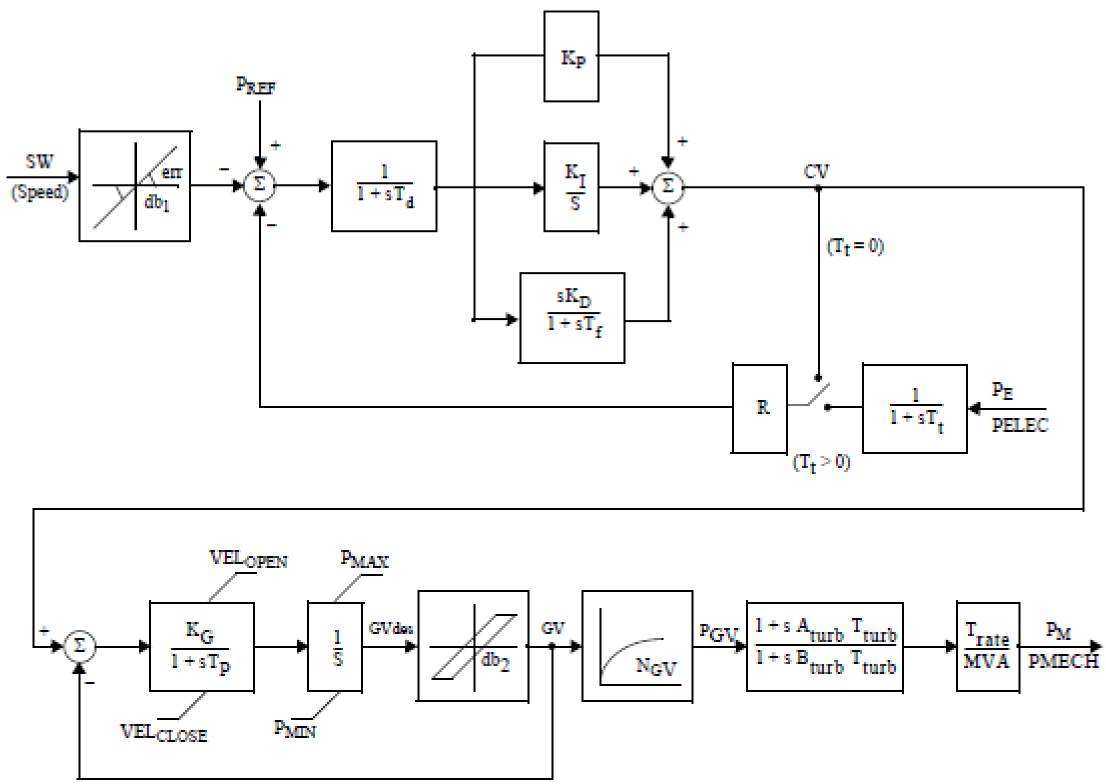


Figure 3-16 WSHYPG Model Block Diagram for Turbine-Governor/Penstock Dynamics

In this model,

db_1 = deadband width (p.u.)

err = deadband hysteresis (p.u.)

T_d = input filter time constant (s)

K_I = integral gain (p.u.)

T_f = derivative time constant (s)

K_D = derivative gain (p.u.)

K_P = proportional gain (p.u.)

R = droop (p.u. on Trate)

T_t = power feedback time constant (s)

K_G = gate servo gain (p.u.)

T_P = gate servo time constant (s)

VEL_{OPEN} = maximum gate opening rate (p.u./s)

VEL_{CLOSE} = maximum gate closing rate (p.u./s)

P_{MAX} = maximum gate opening (p.u.)

P_{MIN} = minimum gate opening (p.u.)

db_2 = deadband (p.u.)

GV_1 = coordinate of power-gate look-up table (p.u. gate)

PGV_1 = coordinate of power-gate look-up table (p.u. power)

GV_2 = coordinate of power-gate look-up table (p.u. gate)

PGV_2 = coordinate of power-gate look-up table (p.u. power)

GV_3 = coordinate of power-gate look-up table (p.u. gate)

PGV_3 = coordinate of power-gate look-up table (p.u. power)

GV_4 = coordinate of power-gate look-up table (p.u. gate)

PGV_4 = coordinate of power-gate look-up table (p.u. power)

GV_5 = coordinate of power-gate look-up table (p.u. gate)

PGV_5 = coordinate of power-gate look-up table (p.u. power)

A_{turb} = turbine lead time constant multiplier

B_{turb} (>0) = turbine lag time constant multiplier

T_{turb} (>0) = turbine time constant (s)

T_{rate} = turbine rating (MW)

3.3 An Example of the Prevalence of the Hydro Models in a Large U.S. Simulation Database Using the PSS®E Software

Section 3.2 showed that the PSS®E software package has a wide variety of models to represent hydro units. Some of these models are used much more often than others. To illustrate this, a typical representation of the eastern U.S. power system was analyzed.

An official MMWG PSS®E stability database named "2016SUM-2010Series-Final-ds_rev3" was used to demonstrate the governor/turbine models that are being used to represent hydro machines in the Eastern Interconnection for stability studies. Table 3.1 shows how often each hydro turbine-governor model in this database is used. Note that this table is provided for illustrative purposes only and should not be construed to imply that any model is better than another model or that the results shown here are typical of those from other systems. Also note that some utilities may use more detailed models when studying dynamic phenomena associated with their particular plants.

The most commonly used hydro model in the Eastern Interconnection is the HYGOV model, which is used to represent about 64% of the units. The next most commonly used model is the IEEEG2 model, which is used for about 15% of the units. Most of the remaining units are modeled using one of the several models that represent PID governors.

Table 3-1 Governor/Turbine Models Used to Represent Hydroelectric Units in a Typical Eastern Interconnection Stability Database Using the PSS®E Software

Area No.	Area Name	HYGOV	HYGOV2	IEEEG2	IEEEG3	PIDGOV	WEHGOV	WPIDHY
1	West	12						
5	Mohawk	2						
6	Capital	7		2				
7	Hudson	1						
9	Dunwoodie	1						
101	ISO-NE	29		5		17		14
103	IESO	102			8		43	9
105	NB	8		9				
106	NS	31						
201	AP	3						
205	AEP	11						
208	DEM	3						
210	SIGE					3		
226	PENLEC	11						
227	METED	1						
228	JCP&L	3						
229	PPL	17						
230	PECO	12						7
295	WEC	29						
320	EKPC	4						
340	CPLE				10			
341	CPLW				5			
343	SCEG			13				
344	SCEG			8				
345	DVP			8			6	7
346	SOCO			80			1	2
347	TVA	153						
351	EES	7						
354	SERU			8				
355	SETH			4				
356	AMMO			2				
363	LGEE	8						
402	PEF	4						
515	SWPA	57						
520	AEPW	4						
523	GRDA	8						
544	EMDE	4						
608	MP	6						
640	NPPD	1						
667	MH		29				12	
672	SPC	7			8		3	
694	ALTE	6						
696	WPS	30						
698	UPPC	7						
	Total	**589**	**29**	**139**	**31**	**20**	**65**	**39**
	% of Total	**64.3**	**3.2**	**15.4**	**3.4**	**2.2**	**7.2**	**4.3**

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Section

4

PSLF Hydro Turbine-Governor Simulation Models

The PSLF program is the second most widely used power system simulation package in the United States. It is used widely in the Western Interconnection, which contains many large hydroelectric plants.

The explanations for the PSLF models are arranged in this section in about the same order as those for the PSS®E models. There are some differences in the models, and these are mentioned as appropriate.

4.1 Simulation Models in PSLF Version 18

4.1.1 GPWSCC Model

The GPWSCC governor model has a PID governor that represents the WECC type GP governor/turbine model. It is similar to the PSS®E model WHHYPG, and the comments given about that model also apply to GPWSCC.

The model block diagram is shown in Figure 4-1, and the parameters of the model are defined in Table 4-1.

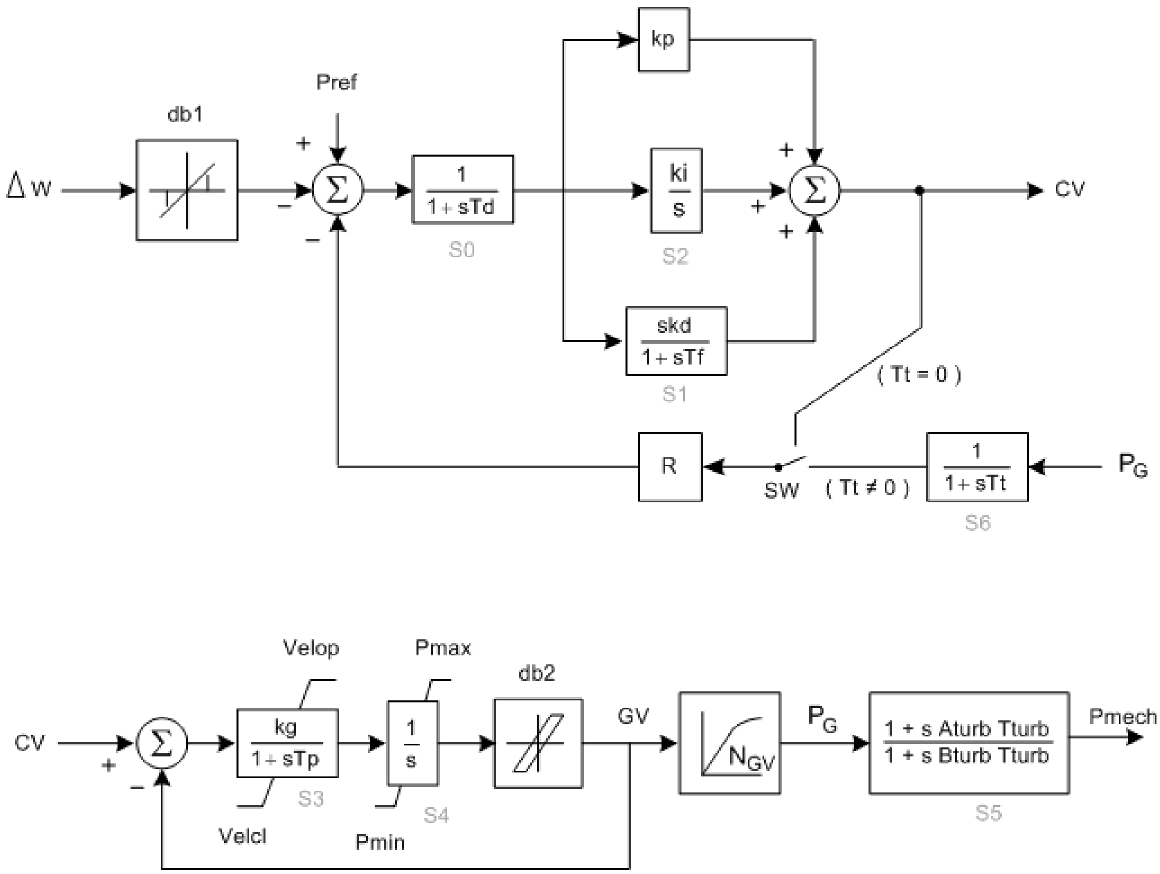

Figure 4-1 Block Diagram of the PSLF GPWSCC Model

Table 4-1 Parameters Used in the PSLF GPWSCC Model

Pmax	Maximum gate opening, p.u. of mwcap
Pmin	Minimum gate opening, p.u. of mwcap
R	Steady-state droop, p.u.
Td	Input filter time constant, s
Tf	Washout time constant, s
Tp	Gate servo time constant, s
Velop	Maximum gate opening velocity, p.u./s
Velcl	Maximum gate closing velocity, p.u./s (<0)
Kp	Proportional gain, p.u.
Kd	Derivative gain, p.u.
Ki	Integral gain, p.u.
Kg	Gate servo gain, p.u.
Tturb	Turbine time constant, s
Aturb	Turbine numerator multiplier
Bturb	Turbine denominator multiplier
Tt	Power feedback time constant, s
db1	Intentional deadband width, Hz
eps	Intentional deadband hysteresis, Hz
db2	Unintentional deadband, MW
Gv1	Nonlinear gain point 1, p.u. gv
Pgv1	Nonlinear gain point 1, p.u. power
Gv2	Nonlinear gain point 2, p.u. gv
Pgv2	Nonlinear gain point 2, p.u. power
Gv3	Nonlinear gain point 3, p.u. gv
Pgv3	Nonlinear gain point 3, p.u. power
Gv4	Nonlinear gain point 4, p.u. gv
Pgv4	Nonlinear gain point 4, p.u. power
Gv5	Nonlinear gain point 5, p.u. gv
Pgv5	Nonlinear gain point 5, p.u. power
Gv6	Nonlinear gain point 6, p.u. gv
Pgv6	Nonlinear gain point 6, p.u. power

4.1.2 G2WSCC Model

The G2WSCC governor model has a double derivative governor that represents the WECC type G2 governor/ turbine model. It is similar to the PSS®E model WHHYDD, and the comments given about that model also apply to G2WSCC.

The model block diagram is shown in Figure 4-2, and the parameters of the model are defined in Table 4-2.

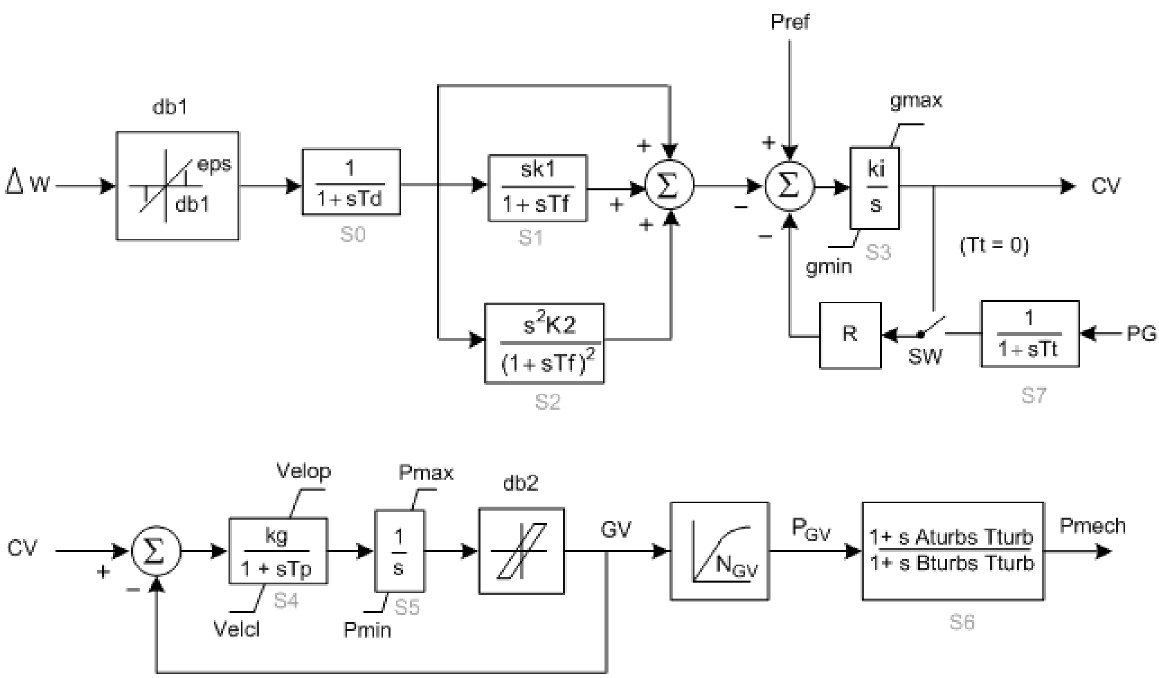

Figure 4-2 Block Diagram of the PSLF G2WSCC Model

Table 4-2 Parameters Used in the PSLF G2WSCC Model

Pmax	Maximum gate opening, p.u. of mwcap
Pmin	Minimum gate opening, p.u. of mwcap
R	Steady state droop, p.u.
Td	Input filter time constant, s
Tf	Washout time constant, s
Tp	Gate servo time constant, s
Velop	Maximum gate opening velocity, p.u./s
Velcl	Maximum gate closing velocity, p.u./s (<0)
K1	Single derivative gain, p.u.
K2	Double derivative gain, p.u.
Ki	Integral gain, p.u.
Kg	Gate servo gain, p.u.
Tturb	Turbine time constant, s
Aturb	Turbine numerator multiplier
Bturb	Turbine denominator multiplier
Tt	Power feedback time constant, s
db1	Intentional deadband width, Hz
eps	Intentional deadband hysteresis, Hz
db2	Unintentional deadband, MW
Gv1	Nonlinear gain point 1, p.u. gv
Pgv1	Nonlinear gain point 1, p.u. power
Gv2	Nonlinear gain point 2, p.u. gv
Pgv2	Nonlinear gain point 2, p.u. power
Gv3	Nonlinear gain point 3, p.u. gv
Pgv3	Nonlinear gain point 3, p.u. power
Gv4	Nonlinear gain point 4, p.u. gv
Pgv4	Nonlinear gain point 4, p.u. power
Gv5	Nonlinear gain point 5, p.u. gv
Pgv5	Nonlinear gain point 5, p.u. power
Gv6	Nonlinear gain point 6, p.u. gv
Pgv6	Nonlinear gain point 6, p.u. power

4.1.3 HYG3 Model

The HYG3 governor model includes a PID governor that can be used to represent the WECC type GP governor/turbine model and a double derivative governor that represents the WECC type G2 governor/turbine model.

The model block diagram is shown in Figure 4-3, and the parameters of the model are defined in Table 4-3.

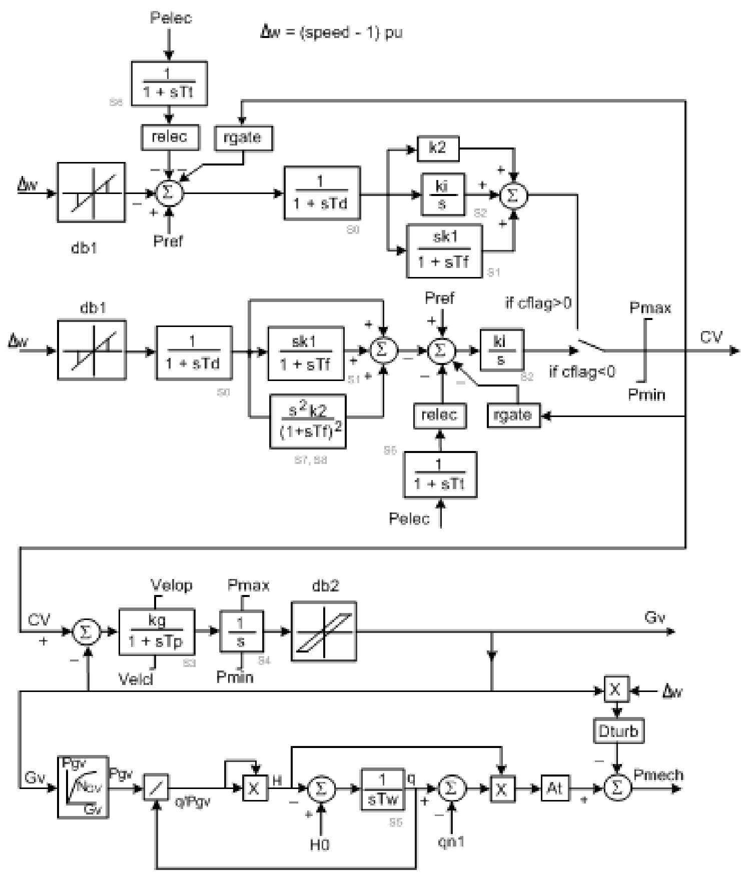

Figure 4-3 Block Diagram of the PSLF HYGOV Model

Table 4-3 Parameters Used in the PSLF HYG3 Model

Variable	Description
Pmax	Maximum gate opening, p.u. of mwcap
Pmin	Minimum gate opening, p.u. of mwcap
Cflag	Governor control flag, 1:PID, –1:double derivative
Rgate	Steady-state droop, p.u., for governor output feedback
Relec	Steady-state droop, p.u., for electrical power feedback
Td	Input filter time constant, s
Tf	Washout time constant, s
Tp	Gate servo time constant, s
Velop	Maximum gate opening velocity, p.u./s
Velcl	Maximum gate closing velocity, p.u./s (<0)
K1	Derivative gain, p.u.
K2	Double derivative gain, p.u., if Cflag = –1
Ki	Integral gain, p.u.
Kg	Gate servo gain, p.u.
Tt	Power feedback time constant, s
db1	Intentional deadband width, Hz
eps	Intentional deadband hysteresis, Hz
db2	Unintentional deadband, MW
Tw	Water inertia time constant, s
At	Turbine gain, p.u.
Dturb	Turbine damping factor, p.u.
qnl	No-load turbine flow at nominal head, p.u.
H0	Turbine nominal head, p.u.
Gv1	Nonlinear gain point 1, p.u. gv
Pgv1	Nonlinear gain point 1, p.u. power
Gv2	Nonlinear gain point 2, p.u. gv
Pgv2	Nonlinear gain point 2, p.u. power
Gv3	Nonlinear gain point 3, p.u. gv
Pgv3	Nonlinear gain point 3, p.u. power
Gv4	Nonlinear gain point 4, p.u. gv
Pgv4	Nonlinear gain point 4, p.u. power
Gv5	Nonlinear gain point 5, p.u. gv
Pgv5	Nonlinear gain point 5, p.u. power
Gv6	Nonlinear gain point 6, p.u. gv
Pgv6	Nonlinear gain point 6, p.u. power

4.1.4 HYGOV Model

As discussed in the section on PSS®E models, HYGOV represents a straightforward hydroelectric plant governor with a simple hydraulic representation of the penstock with unrestricted head race and tail race and no surge tank. The PSLF drawing of this governor is shown in Figure 4-4, and the parameters of the model are defined in Table 4-4. There are some model differences between the two programs. The PSLF model includes a deadband and lead/lag filter on the primary speed input. It also has a curve that relates power to gate opening to model nonlinearities in this relationship. This curve can be set to represent linear, Francis/Pelton, or Kaplan turbine constants.

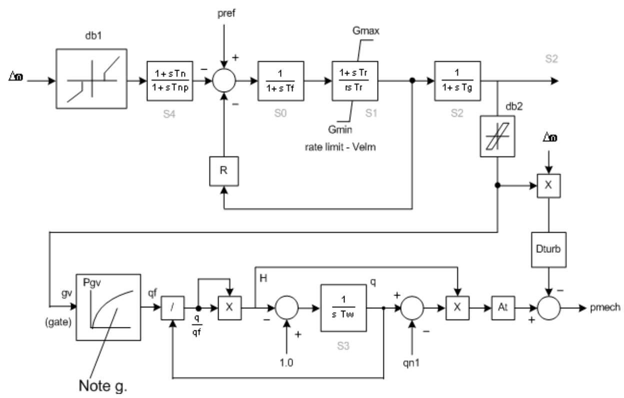

Figure 4-4 Block Diagram of the PSLF HYGOV Model

Table 4-4 Parameters used in the PSLF HYGOV Model

Variable	Description
Rperm	Permanent droop (R), p.u.
rtemp	Temporary droop (r), p.u.
Tr	Washout time constant, s
Tf	Filter time constant, s
Tg	Gate servo time constant, s
Velm	Maximum gate velocity, p.u./s
Gmax	Maximum gate opening, p.u. of mwcap
Gmin	Minimum gate opening, p.u. of mwcap
Tw	Water inertia time constant, s
At	Turbine gain, p.u.
Dturb	Turbine damping factor, p.u.
qnl	No-load flow at nominal head, p.u.
ttrip	Not used
tn	Lead time constant, s
tnp	Lag time constant, s
db1	Intentional deadband width, Hz
eps	Intentional deadband hysteresis, Hz
db2	Unintentional deadband, MW
GV0	Nonlinear gain point 0, p.u. gv
Pgv0	Nonlinear gain point 0, p.u. power
GV1	Nonlinear gain point 1, p.u. gv
Pgv1	Nonlinear gain point 1, p.u. power
GV2	Nonlinear gain point 2, p.u. gv
Pgv2	Nonlinear gain point 2, p.u. power
GV3	Nonlinear gain point 3, p.u. gv
Pgv3	Nonlinear gain point 3, p.u. power
GV4	Nonlinear gain point 4, p.u. gv
Pgv4	Nonlinear gain point 4, p.u. power
GV5	Nonlinear gain point 5, p.u. gv
Pgv5	Nonlinear gain point 5, p.u. power
hdam	Head available at dam, p.u.
Bgv0	Kaplan blade servo point 0, p.u.
Bgv1	Kaplan blade servo point 1, p.u.
Bgv2	Kaplan blade servo point 2, p.u.
Bgv3	Kaplan blade servo point 3, p.u.
Bgv4	Kaplan blade servo point 4, p.u.
Bgv5	Kaplan blade servo point 5, p.u.
bmax	Maximum blade adjustment factor
tblade	Blade servo time constant, s

4.1.5 HYGOV4 Model

This governor represents plants with a straightforward penstock configuration and hydraulic governor of the traditional dashpot design. It has the same capability to model the Francis/Pelton or Kaplan turbine as the PSLF HYGOV model. The model block diagram is shown in Figure 4-5 and the parameters of the model are defined in Table 4-5.

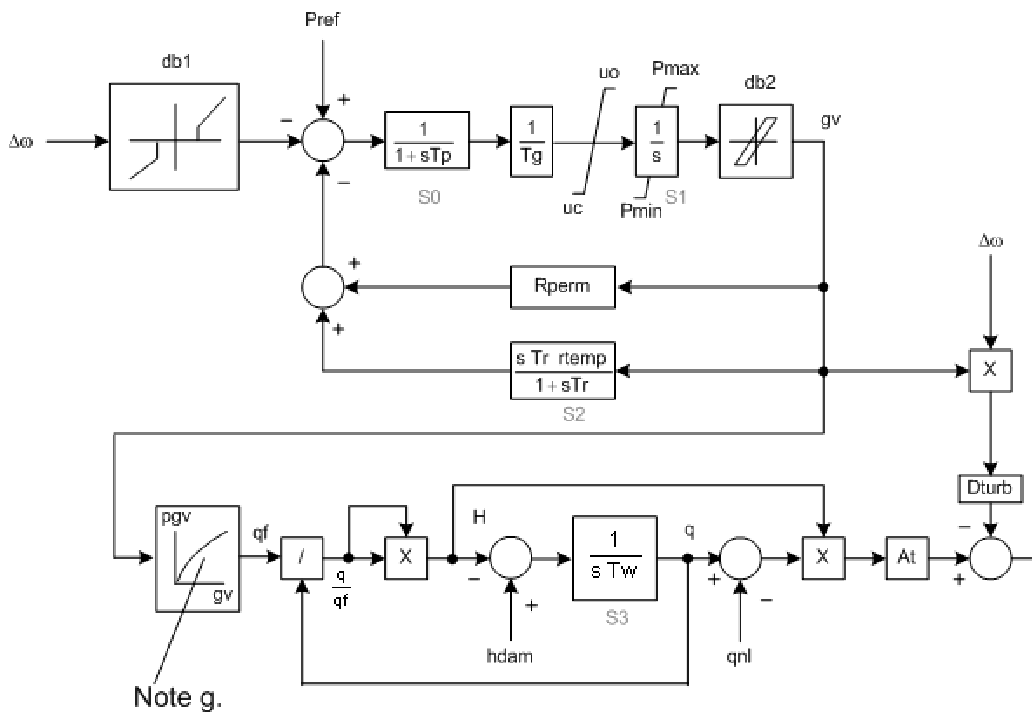

Figure 4-5 Block Diagram of the PSLF HYGOV4 Model

Table 4-5 Parameters Used in the PSLF HYGOV4 Model

Variable	Description
Tg	Gate servo time constant, s
Tp	Pilot servo time constant, s
uo	Max gate opening velocity, p.u./s
uc	Max gate closing velocity, p.u./s
Pmax	Maximum gate opening, p.u. of mwcap
Pmin	Minimum gate opening, p.u. of mwcap
Rperm	Permanent droop (R), p.u.
rtemp	Temporary droop (r), p.u.
Tr	Dashpot time constant, s
Tw	Water inertia time constant, s
At	Turbine gain, p.u.
Dturb	Turbine damping factor, p.u.
hdam	Head available at dam, p.u.
qnl	0 No-load flow at nominal head, p.u.
db1	Intentional deadband width, Hz
eps	Intentional db hysteresis, Hz
db2	Unintentional deadband, MW
GV0	Nonlinear gain point 0, p.u. gv
Pgv0	Nonlinear gain point 0, p.u. power
GV1	Nonlinear gain point 1, p.u. gv
Pgv1	Nonlinear gain point 1, p.u. power
GV2	Nonlinear gain point 2, p.u. gv
Pgv2	Nonlinear gain point 2, p.u. power
GV3	Nonlinear gain point 3, p.u. gv
Pgv3	Nonlinear gain point 3, p.u. power
GV4	Nonlinear gain point 4, p.u. gv
Pgv4	Nonlinear gain point 4, p.u. power
GV5	Nonlinear gain point 5, p.u. gv
Pgv5	Nonlinear gain point 5, p.u. power
hdam	Head available at dam, p.u.
Bgv0	Kaplan blade servo point 0, p.u.
Bgv1	Kaplan blade servo point 1, p.u.
Bgv2	Kaplan blade servo point 2, p.u.
Bgv3	Kaplan blade servo point 3, p.u.
Bgv4	Kaplan blade servo point 4, p.u.
Bgv5	Kaplan blade servo point 5, p.u.
Bmax	Maximum blade adjustment factor
tblade	Blade servo time constant, s

Note: The parameter hdam appears in the data list twice. Please see the PSLF manual for the full explanation of its use.

4.1.6 HYGOVR Model

This is the PSLF fourth-order lead/lag governor for a unit with digital controls. The PSLF model allows a nonlinear relationship between the gate position and power. The block diagram is shown in Figure 4-6, and the parameters of the model are defined in Table 4-6.

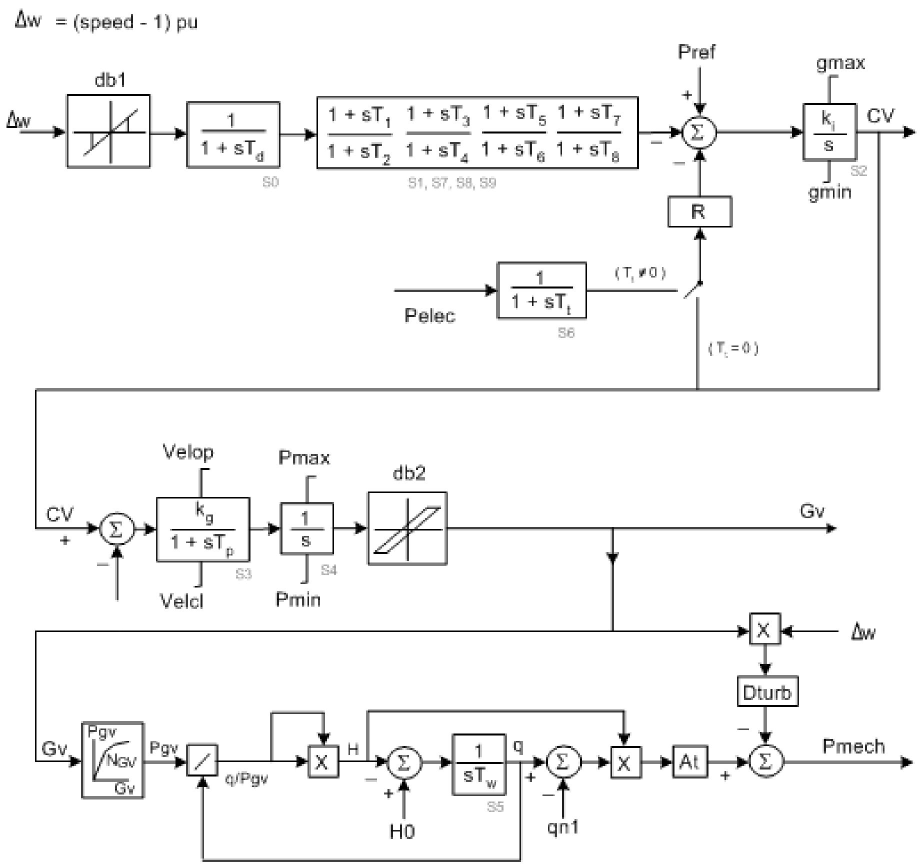

Figure 4-6 Block Diagram of the PSLF HYGOVR Model

Table 4-6 Parameters Used in the PSLF HYGOVR Model

Variable	Description
Pmax	Maximum gate opening, p.u. of mwcap
Pmin	Minimum gate opening, p.u. of mwcap
R	Steady-state droop, p.u.
Td	Input filter time constant, s
T1	Lead time constant 1, s
T2	Lag time constant 1, s
T3	Lead time constant 2, s
T4	Lag time constant 2, s
T5	Lead time constant 3, s
T6	Lag time constant 3, s
T7	Lead time constant 4, s
T8	Lag time constant 4, s
Tp	Gate servo time constant, s
Velop	Maximum gate opening velocity, p.u./s
Velcl	Maximum gate closing velocity, p.u./s (<0)
Ki	Integral gain, p.u.
Kg	Gate servo gain, p.u.
gmax	Maximum governor output, p.u.
gmin	Minimum governor output, p.u.
Tt	Power feedback time constant, s
db1	Intentional deadband width, Hz
eps	Intentional deadband hysteresis, Hz
db2	Unintentional deadband, MW
Tw	Water inertia time constant, s
At	Turbine gain, p.u.
Dturb	Turbine damping factor, p.u.
qnl	No-load turbine flow at nominal head, p.u.
H0	Turbine nominal head, p.u.
Gv1	Nonlinear gain point 1, p.u. gv
Pgv1	Nonlinear gain point 1, p.u. power
Gv2	Nonlinear gain point 2, p.u. gv
Pgv2	Nonlinear gain point 2, p.u. power
Gv3	Nonlinear gain point 3, p.u. gv
Pgv3	Nonlinear gain point 3, p.u. power
Gv4	Nonlinear gain point 4, p.u. gv
Pgv4	Nonlinear gain point 4, p.u. power
Gv5	Nonlinear gain point 5, p.u. gv
Pgv5	Nonlinear gain point 5, p.u. power
Gv6	Nonlinear gain point 6, p.u. gv
Pgv6	Nonlinear gain point 6, p.u. power

4.1.7 IEEEG3 Model

This is the standard IEEE hydro turbine/governor model for a unit with straightforward penstock design and hydraulic dashpot governors. The PSLF model includes an optional deadband and nonlinear gain. The block diagram for this model is shown in Figure 4-7, and the parameters of the model are defined in Table 4.7.

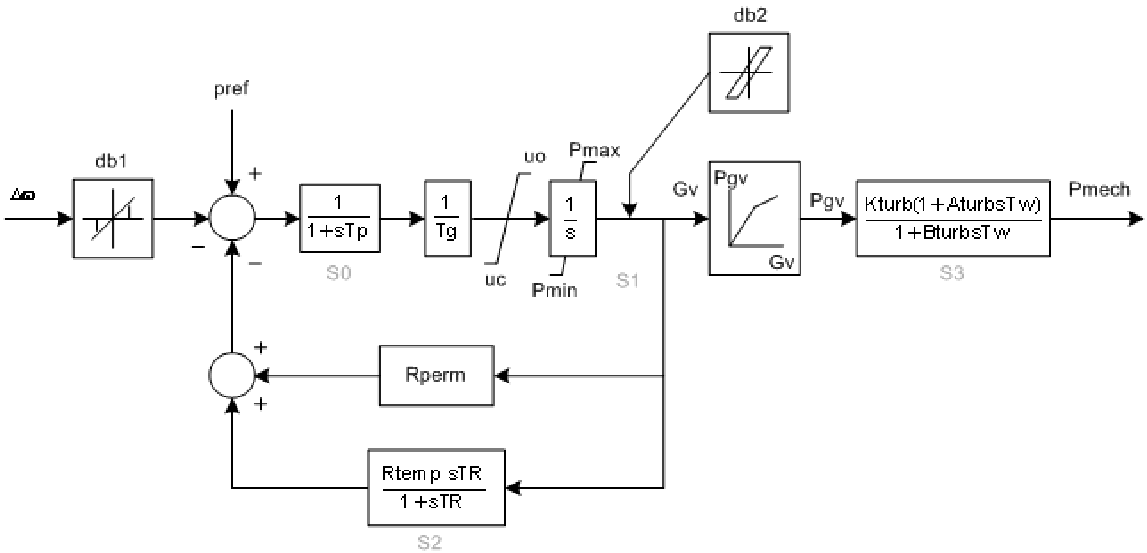

Figure 4-7 Block Diagram of the PSLF IEEEG3 Model

Table 4-7 Parameters Used in the PSLF IEEEG3 Model

Variable	Description
Tg	Gate servo time constant, s
Tp	Pilot servo valve time constant, s
Uo	Maximum gate opening velocity, p.u./s
Uc	Maximum gate closing velocity, p.u./s (<0)
Pmax	Maximum gate opening, p.u. of mwcap
Pmin	Minimum gate opening, p.u. of mwcap
Rperm	Permanent droop, p.u.
Rtemp	Temporary droop, p.u.
Tr	Dashpot time constant, s
Tw	Water inertia time constant, s
Kturb	Turbine gain, p.u.
Aturb	Turbine numerator multiplier
Bturb	Turbine denominator multiplier
Spare	Unused parameter
db1	Intentional deadband width, Hz
eps	Intentional deadband hysteresis, Hz
db2	Unintentional deadband, MW
Gv1	Nonlinear gain point 1, p.u. gv
Pgv1	Nonlinear gain point 1, p.u. power
Gv2	Nonlinear gain point 2, p.u. gv
Pgv2	Nonlinear gain point 2, p.u. power
Gv3	Nonlinear gain point 3, p.u. gv
Pgv3	Nonlinear gain point 3, p.u. power
Gv4	Nonlinear gain point 4, p.u. gv
Pgv4	Nonlinear gain point 4, p.u. power
Gv5	Nonlinear gain point 5, p.u. gv
Pgv5	Nonlinear gain point 5, p.u. power
Gv6	Nonlinear gain point 6, p.u. gv
Pgv6	Nonlinear gain point 6, p.u. power

4.1.8 PIDGOV Model

This model represents hydro turbine/governor units with straightforward penstock configurations and three term electro/hydraulic governors (also sometimes called Woodward electronic governors). The block diagram for the model is shown in Figure 4-8, and the parameters of the model are defined in Table 4-8.

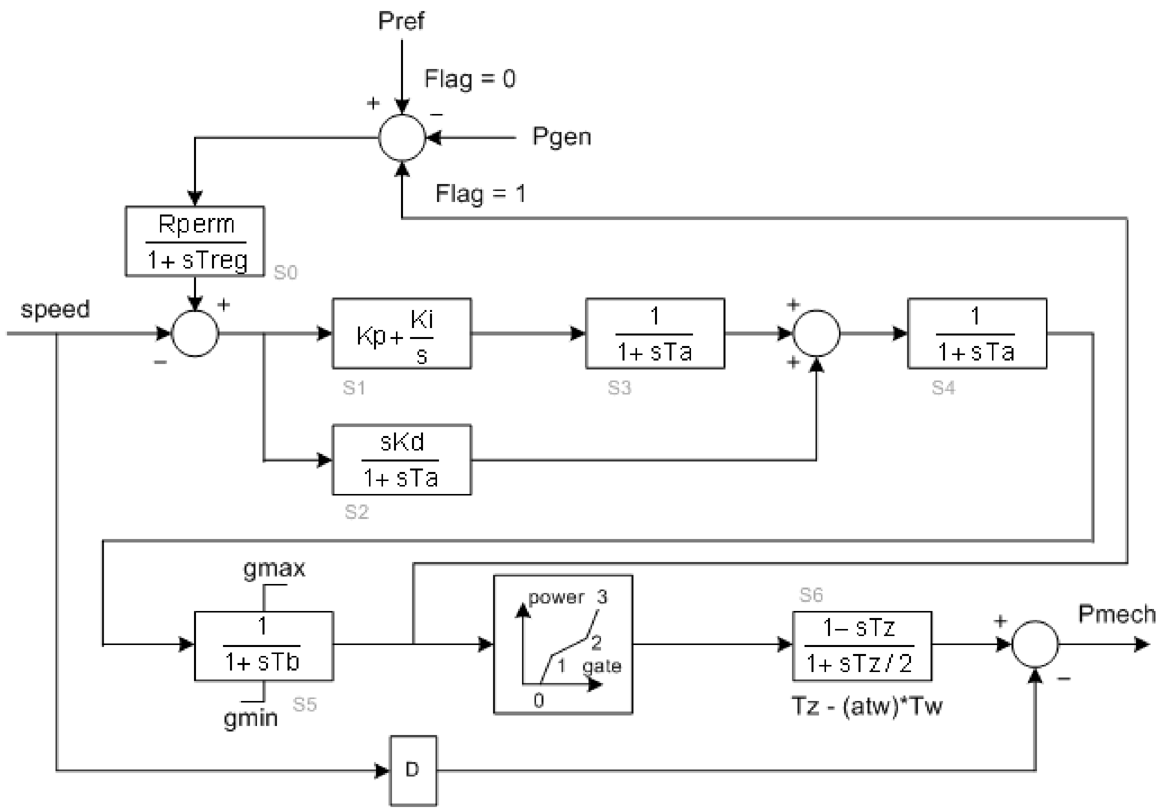

Figure 4-8 Block Diagram of the PSLF PIDGOV Model

Table 4-8 Parameters Used in the PSLF PIDGOV Model

Variable	Description
Treg	Speed detector time constant, s
rperm	Permanent drop, p.u.
Kp	Proportional gain, p.u.
Ki	Reset gain, p.u./s
Kd	Derivative gain, p.u.
Ta	Controller time constant, s
Tb	Gate servo time constant, s
Velmax	Maximum gate opening velocity, p.u./s
Velmin	Maximum gate closing velocity, p.u./s
Gmax	Maximum gate opening, p.u.
Gmin	Minimum gate opening, p.u.
Tw	Water inertia time constant, p.u.
Pmax	Maximum power, p.u. (not used)
Pmin	Minimum power, p.u. (not used)
Dturb	Turbine damping factor, p.u.
g0	Gate opening at speed no load, p.u.
g1	Intermediate gate opening, p.u.
p1	Power at gate opening g1, p.u.
g2	Intermediate gate opening, p.u.
p2	Power at gate opening g2, p.u.
p3	Power at full opened gate, p.u.
atw	Factor multiplying Tw, p.u.
Flag	Feedback signal type flag

4.1.9 HYPID Model

This model also represents the straight forward penstock configuration. The governor has a PID controller. The model can model Kaplan blade angle adjustment and diagonal flow turbines. A block diagram of the model is shown in Figure 4-9 and the parameters of the model are defined in Table 4-9.

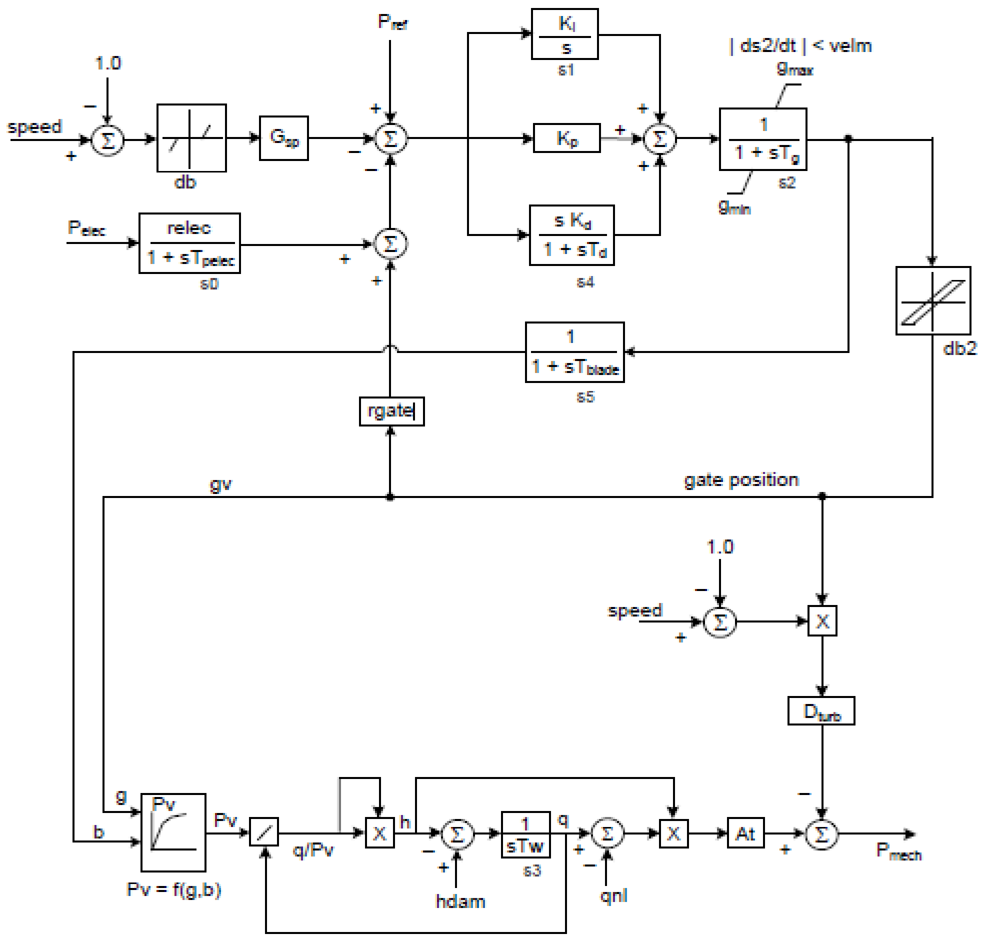

Figure 4-9 Block Diagram of the PSLF HYPID Model

Table 4-9 Parameters Used in the HYPID Model

Variable	Description
relec	Governing droop, p.u.
tpelec	Power transducer time constant, s
kp	Proportional gain
ki	Integral gain
kd	Derivative gain
td	Derivative element time constant, s
tg	Gate servo time constant, s
velm	Maximum gate velocity, p.u./s
gmax	Maximum gate opening, p.u. of mwcap
gmin	Minimum gate opening, p.u. of mwcap
tw	Water inertia time constant, s
at	Turbine gain, p.u.
dturb	Turbine damping factor, p.u.
qnl	No-load flow at nominal head, p.u.
gsp	Speed input gain (nominally 1.0)
db1	Intentional deadband width, Hz
eps	Intentional deadband hysteresis, Hz
db2	Unintentional deadband, MW
GV0	Nonlinear gain point 0, p.u. gv
Pgv0	Nonlinear gain point 0, p.u. power
GV1	Nonlinear gain point 1, p.u. gv
Pgv1	Nonlinear gain point 1, p.u. power
GV2	Nonlinear gain point 2, p.u. gv
Pgv2	Nonlinear gain point 2, p.u. power
GV3	Nonlinear gain point 3, p.u. gv
Pgv3	Nonlinear gain point 3, p.u. power
GV4	Nonlinear gain point 4, p.u. gv
Pgv4	Nonlinear gain point 4, p.u. power
GV5	Nonlinear gain point 5, p.u. gv
Pgv5	Nonlinear gain point 5, p.u. power
hdam	Head available at dam, p.u.
Bgv0	Kaplan blade servo point 0, p.u.
Bgv1	Kaplan blade servo point 1, p.u.
Bgv2	Kaplan blade servo point 2, p.u.
Bgv3	Kaplan blade servo point 3, p.u.
Bgv4	Kaplan blade servo point 4, p.u.
Bgv5	Kaplan blade servo point 5, p.u.
bmax	Maximum blade adjustment factor
tblade	Blade servo time constant, s
rgate	Governing droop using gate position, p.u.

4.1.10 HYST1 Model

This PSLF model is for a hydro unit with a penstock, surge tank and inlet tunnel. The governor is a Woodward electro hydraulic PID. A block diagram of the model is shown in Figure 4-10, and the parameters of the model are defined in Table 4-10. The turbine/ penstock characteristics are contained in the function G(s) shown in the diagram.

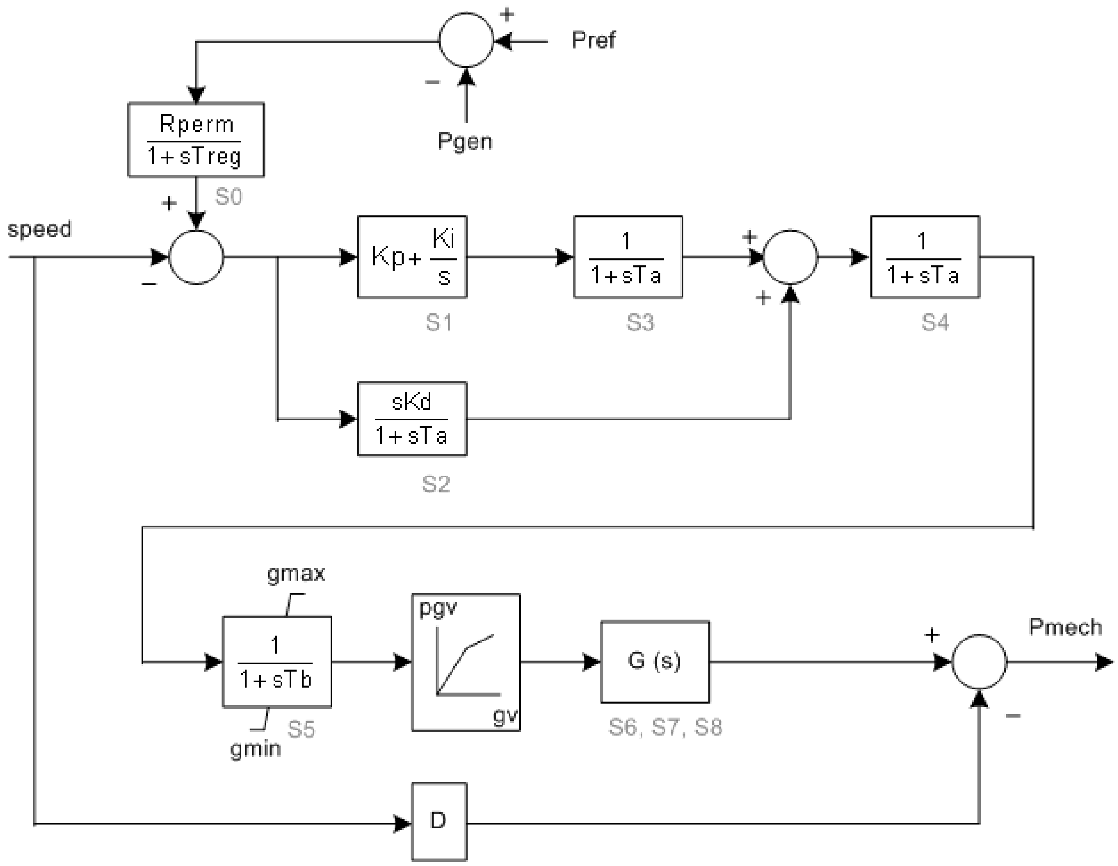

Figure 4-10 Block Diagram of the PSLF HYST1 Model

Table 4-10 Parameters Used in the PSLF HYST1 Model

Variable	Description
Treg	Input time constant of governor, s
Rperm	Governor droop, per unit
Kp	Governor proportional gain
Ki	Governor integral gain
Kd	Governor derivative gain
Ta	Governor high-frequency cutoff time constant
Tb	Gate servo time constant
Velmax	Max gate opening velocity, p.u./s
Velmin	Min gate closing velocity, p.u./s
Gmax	Max gate opening, p.u.
Gmin	Min gate opening, p.u.
Pmax	Not used
Pmin	Not used
D	Turbine damping coefficient
Twp	Penstock water time constant, s
Twt	Tunnel water time constant, s
flos	Tunnel Loss Coefficient, p.u.
As1	Area constant of Upper Surge Tank, s
As2	Area constant of Lower Surge Tank, s
h2	Level of surge tank size change, p.u.

4.1.11 W2301 Model

The PSLF W2301 model is for a hydro unit with a Woodward 2301 controller. The block diagram is shown in Figure 4-11, and the parameters of the model are defined in Table 4-11.

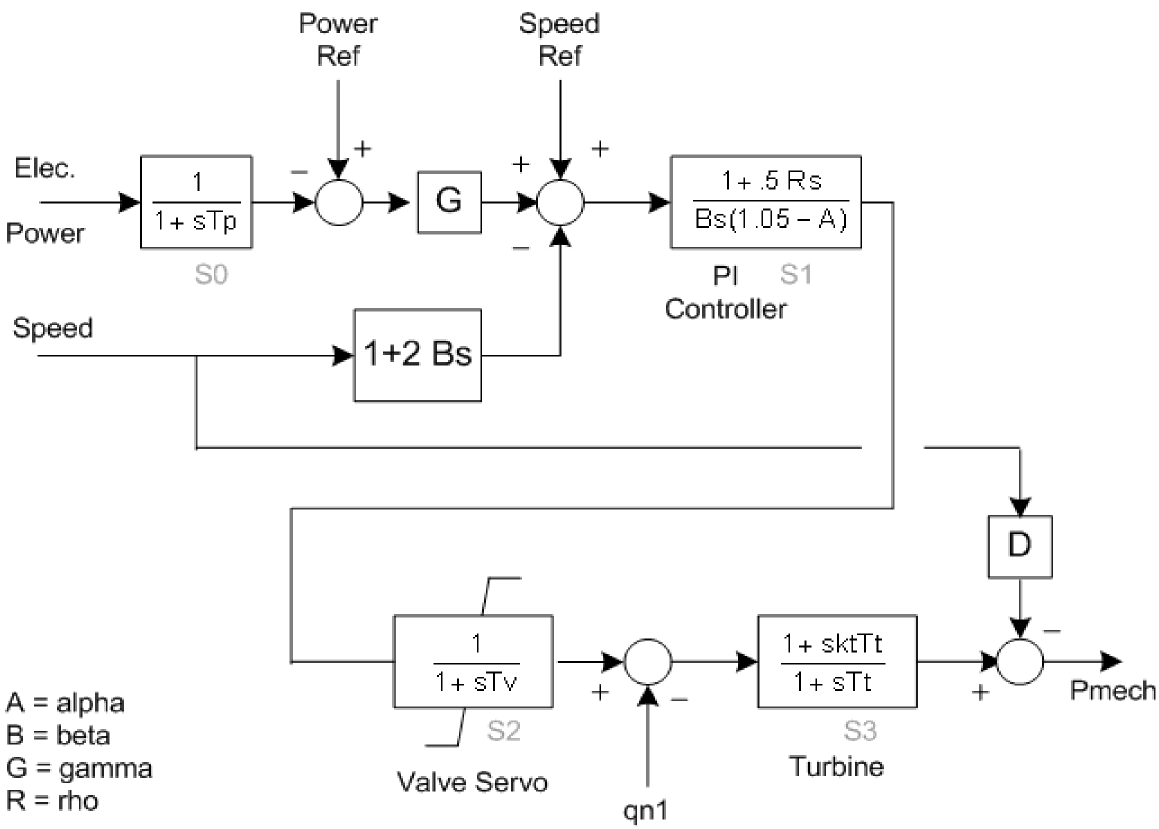

Figure 4-11 Block Diagram of the PSLF W2301 Model

Table 4-11 Parameters Used in the PSLF W2301 Model

Variable	Description
tp	Power transducer time constant
alpha	Droop setting
beta	Reset setting
rho	Compensation
gamma	Gain setting, p.u.
gain	Turbine gain
tv	Valve actuator time constant, s
velamx	Maximum valve velocity, ps
gmax	Maximum valve opening, p.u.
gmin	Minimum valve opening, p.u.
gnl	Valve opening at no load, p.u.
tturb	Turbine time constant, s
d	Turbine damping coefficient
kt	Turbine lead-lag ratio

4.1.12 HYGOV8 Model

The HYGOV8 hydro governor model can represent up to four units on a common penstock. It represents a PID governor. The block diagram of the HYGOV8 model is shown in Figure 4-12, and the parameters of the model are defined in Table 4-12.

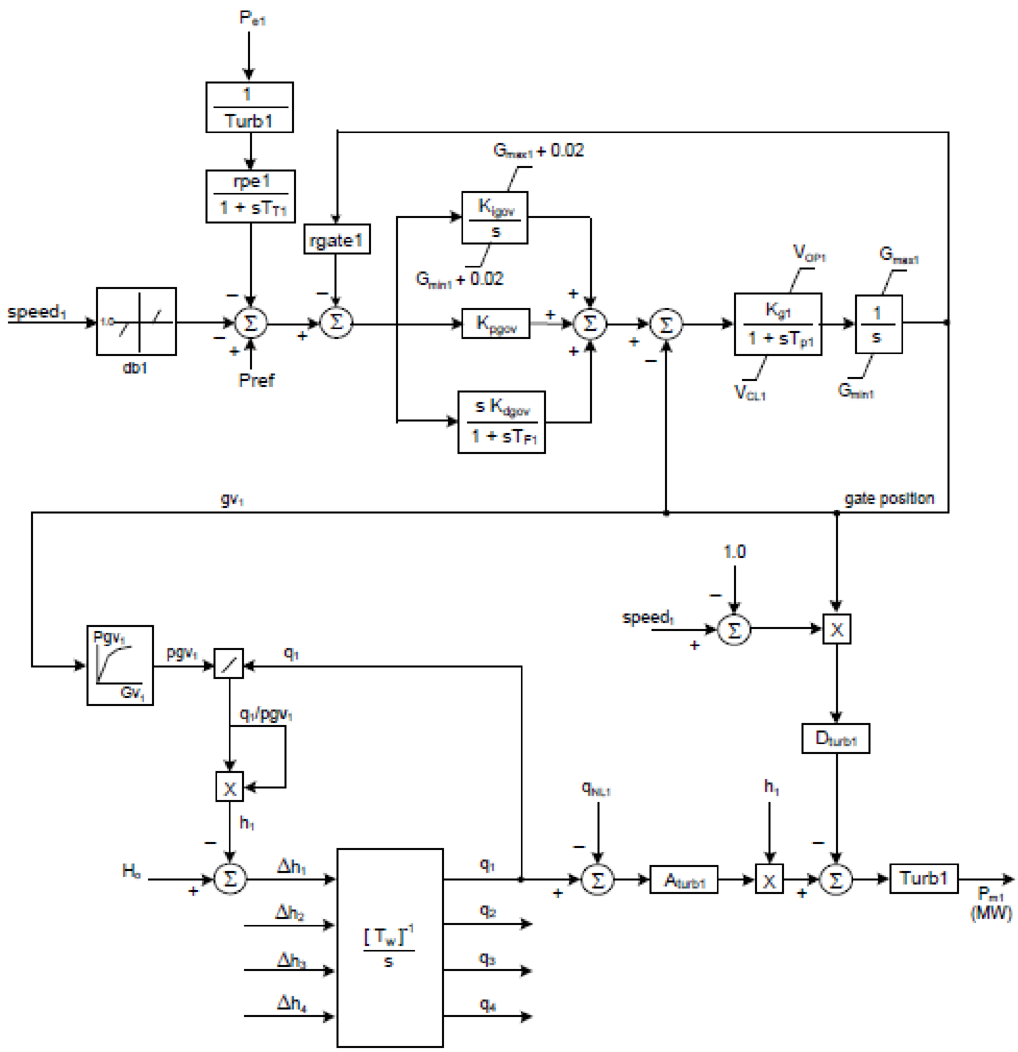

Figure 4-12 Block Diagram of the PSLF HYGOV8 Model

Table 4-12 Parameters Used in the PSLF HYGOV8 Model

Variable	Description
ibus1	Bus number of Unit 1
ibus2	Bus number of Unit 2, may be set to 0 to disable the portion of model for this unit
ibus3	Bus number of Unit 3, may be set to 0 to disable the portion of model for this unit
ibus4	Bus number of Unit 4, may be set to 0 to disable the portion of model for this unit
id1	Machine ID (real variable) for Unit 1
id2	Machine ID (real variable) for Unit 2
id3	Machine ID (real variable) for Unit 3
id4	Machine ID (real variable) for Unit 4
turb1	Turbine MW rating for Unit 1
The following parameters are for Unit 1 governor	
rgate1	Steady-state droop for gate position feedback
rpe1	Steady-state droop for electrical power feedback
tt1	Power feedback filter time constant, s
tf1	Derivative control time constant, s
kpgov1	Governor proportional gain, p.u.
kigov1	Governor integral gain, p.u.
kdgov1	Governor derivative gain, p.u.
tdgov1	Share time constant
td1	Speed error signal filter time constant, s
tp1	Pilot valve time constant, s
vop1	Maximum gate opening velocity, p.u./s
vcl1	Maximum gate closing velocity, p.u./s
kg1	Distribution valve gain, p.u.
ho	Plant net head, p.u.
gmax1	Maximum gate position, p.u.
gmin1	Minimum gate position, p.u.
tw1	Water starting time (s) of Unit 1 flow for entire length
tw12	Water starting time (s) of Unit 1 flow common length of penstock shared with Unit 2
tw13	Water starting time (s) of Unit 1 flow common length of penstock shared with Unit 3
tw14	Water starting time (s) of Unit 1 flow common length of penstock shared with Unit 4
turb2	Turbine MW rating for Unit 2
The following parameters are for Unit 2 governor	
rgate2	Steady-state droop for gate position feedback
rpe2	Steady-state droop for electrical power feedback
tt2	Power feedback filter time constant, s
tf2	Derivative control time constant, s
kpgov2	Governor proportional gain, p.u.
kigov2	Governor integral gain, p.u.
kdgov2	Governor derivative gain, p.u.
tdgov2	Share time constant
td2	Speed error signal filter time constant, s
tp2	Pilot valve time constant, s

Variable	Description
vop2	Maximum gate opening velocity, p.u./s
vcl2	Maximum gate closing velocity, p.u./s
kg2	Distribution valve gain, p.u.
gmax2	Maximum gate position, p.u.
gmin2	Minimum gate position, p.u.
tw2	Water starting time (s) of Unit 2 flow for entire length
tw21	Water starting time (s) of Unit 2 flow common length of penstock shared with Unit 1
tw23	Water starting time (s) of Unit 2 flow common length of penstock shared with Unit 3
tw24	Water starting time (s) of Unit 2 flow common length of penstock shared with Unit 4
turb3	Turbine MW rating for Unit 3
The following parameters are for Unit 3 governor	
rgate3	Steady-state droop for gate position feedback
rpe3	Steady-state droop for electrical power feedback
tt3	Power feedback filter time constant, s
tf3	Derivative control time constant, s
kpgov3	Proportional gain, p.u.
kigov3	Governor integral gain, p.u.
kdgov3	Governor derivative gain, p.u.
tdgov3	Share time constant
td3	Speed error signal filter time constant, s
tp3	Pilot valve time constant, s
vop3	Maximum gate opening velocity, p.u./s
vcl3	Maximum gate closing velocity, p.u./s
kg3	Distribution valve gain, p.u.
gmax3	Maximum gate position, p.u.
gmin3	Minimum gate position, p.u.
tw3	Water starting time (s) of Unit 3 flow for entire length
tw31	Water starting time (s) of Unit 3 flow common length of penstock shared with Unit 1
tw32	Water starting time (s) of Unit 3 flow common length of penstock shared with Unit 2
tw34	Water starting time (s) of Unit 3 flow common length of penstock shared with Unit 4
turb4	Turbine MW rating for Unit 4
The following parameters are for Unit 4 governor	
rgate4	Steady-state droop for gate position feedback
rpe4	Steady-state droop for electrical power feedback
tt4	Power feedback filter time constant, s
tf4	Derivative control time constant, s
kpgov4	Governor proportional gain, p.u.
kigov4	Governor integral gain, p.u.
kdgov4	Governor derivative gain, p.u.
tdgov4	Share time constant
td4	Speed error signal filter time constant, s
tp4	Pilot valve time constant, s
vop4	Maximum gate opening velocity, p.u./s

Variable	Description
vcl4	Maximum gate closing velocity, p.u./s
kg4	Distribution valve gain, p.u.
gmax4	Maximum gate position, p.u.
gmin4	Minimum gate position, p.u.
tw4	Water starting time (s) of Unit 4 flow for entire length
tw41	Water starting time (s) of Unit 4 flow common length of penstock shared with Unit 1
tw42	Water starting time (s) of Unit 4 flow common length of penstock shared with Unit 2
tw43	Water starting time (s) of Unit 4 flow common length of penstock shared with Unit 3
aturb1	Turbine gain for Unit 1, p.u.
qnl1	No load flow for Unit 1, p.u.
aturb2	Turbine gain for Unit 2, p.u.
qnl2	No load flow for Unit 2, p.u.
aturb3	Turbine gain for Unit 3, p.u.
qnl3	No load flow for Unit 3, p.u.
aturb4	Turbine gain for Unit 4, p.u.
qnl4	No load flow for Unit 4, p.u.
dturb1	Turbine damping factor for Unit 1, p.u.
dturb2	Turbine damping factor for Unit 2, p.u.
dturb3	Turbine damping factor for Unit 3, p.u.
dturb4	Turbine damping factor for Unit 4, p.u.
db11	Intentional deadband width for Unit 1, p.u.
db12	Intentional deadband width for Unit 2, p.u.
db13	Intentional deadband width for Unit 3, p.u.
db14	Intentional deadband width for Unit 4, p.u.
Lookup table for nonlinear gain on Unit 1	
gv01	Nonlinear gain point 1, p.u. gv
pgv01	Nonlinear gain point 1, p.u. power
gv11	Nonlinear gain point 2, p.u. gv
pgv11	Nonlinear gain point 2, p.u. power
gv21	Nonlinear gain point 3, p.u. gv
pgv21	Nonlinear gain point 3, p.u. power
gv31	Nonlinear gain point 4, p.u. gv
pgv31	Nonlinear gain point 4, p.u. power
gv41	Nonlinear gain point 5, p.u. gv
pgv41	Nonlinear gain point 5, p.u. power
gv51	Nonlinear gain point 6, p.u. gv
pgv51	Nonlinear gain point 6, p.u. power
Lookup table for nonlinear gain on Unit 2	
gv02	Nonlinear gain point 1, p.u. gv
pgv02	Nonlinear gain point 1, p.u. power
gv12	Nonlinear gain point 2, p.u. gv
pgv12	Nonlinear gain point 2, p.u. power
gv22	Nonlinear gain point 3, p.u. gv

Variable	Description
pgv22	Nonlinear gain point 3, p.u. power
gv32	Nonlinear gain point 4, p.u. gv
pgv32	Nonlinear gain point 4, p.u. power
gv42	Nonlinear gain point 5, p.u. gv
pgv42	Nonlinear gain point 5, p.u. power
gv52	Nonlinear gain point 6, p.u. gv
pgv52	Nonlinear gain point 6, p.u. power
Lookup table for nonlinear gain on Unit 3	
gv03	Nonlinear gain point 1, p.u. gv
pgv03	Nonlinear gain point 1, p.u. power
gv13	Nonlinear gain point 2, p.u. gv
pgv13	Nonlinear gain point 2, p.u. power
gv23	Nonlinear gain point 3, p.u. gv
pgv23	Nonlinear gain point 3, p.u. power
gv33	Nonlinear gain point 4, p.u. gv
pgv33	Nonlinear gain point 4, p.u. power
gv43	Nonlinear gain point 5, p.u. gv
pgv43	Nonlinear gain point 5, p.u. power
gv53	Nonlinear gain point 6, p.u. gv
pgv53	Nonlinear gain point 6, p.u. power
Lookup table for nonlinear gain on Unit 4	
gv04	Nonlinear gain point 1, p.u. gv
pgv04	Nonlinear gain point 1, p.u. power
gv14	Nonlinear gain point 2, p.u. gv
pgv14	Nonlinear gain point 2, p.u. power
gv24	Nonlinear gain point 3, p.u. gv
pgv24	Nonlinear gain point 3, p.u. power
gv34	Nonlinear gain point 4, p.u. gv
pgv34	Nonlinear gain point 4, p.u. power
gv44	Nonlinear gain point 5, p.u. gv
pgv44	Nonlinear gain point 5, p.u. power
gv54	Nonlinear gain point 6, p.u. gv
pgv54	Nonlinear gain point 6, p.u. power

4.2 An Example of the Prevalence of the Hydro Models in a WECC Region Database Using the PSLF Software

Section 4.1 showed that the PSLF software package has a wide variety of models to represent hydro units. Some models are used much more often than others. To illustrate this, a typical representation of the Western U.S. power system was analyzed.

An official WECC PSLF power flow case named “17hw2a.sav,” dated April 26, 2012, and the corresponding dynamics data file named “17hw21.dyd” of the same date were obtained and examined to demonstrate the governor/turbine models that are being used to represent hydro machines in the Western Interconnection for stability studies. Table 4-13 shows how often each hydro turbine-governor model is used. Note that this table is provided for illustrative purposes only and should not be construed to imply that any model is better than another model or that the results shown here are typical of those from other systems. Also note that some utilities may use more detailed models when studying dynamic phenomena associated with their particular plants.

The most commonly used hydro models in the Western Interconnection are the HYGOV, IEEEG3, HYG3, GPWSCC, and HYGOV4 models, all of which are used to represent more than 10% of the units.

Table 4-13 Governor/Turbine PSLF Models Used to Represent Hydroelectric Units in a Typical Western Interconnection Stability Database

PSLF Model	Closest PSS®E Model	Number of Occurrences	% of Total
HYG3	WSHYGP and WSHYDD	133	13.8
HYGOV	HYGOV and HYGOV4	257	26.7
HYGOV4	HYGOV and HYGOV4	111	11.5
HYGOVR		14	1.5
HYST1		0	0.0
PIDGOV	PIDGOV	67	7.0
GPWSCC	WSHYGP and WSHYDD	112	11.6
G2WSCC	WSHYDD	34	3.5
HYPID		0	0.0
IEEEG3	IEEEG3	232	24.1
W2301		3	0.3
Total		**963**	**100.0**

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Section

5

Modeling of Conventional Pumped Storage Hydro Plants

Conventional pumped storage hydro (CPSH) units have many similarities to conventional hydro plants. The major difference is, of course, that the flow is bidirectional. Usually, but not always, the same equipment is used for both generation and pumping; thus, the synchronous generator also operates as a motor, and the hydro turbine also operates as a pump. Both components are therefore reversible in their functionality. Some plants, particularly those with very high heads, may require separate turbines and pumps.

In practical applications, the transition from a generating to a pumping mode of operation (or vice versa) is performed by the operator and takes several minutes (i.e., it is usually not a subject of dynamic simulation studies, except possibly for those used in the initial design of the plant). Thus, in most simulation studies, the generating and pumping modes of operation for CPSH units are studied separately. The system conditions being analyzed are appropriate for one mode or the other; for example, studies performed at peak load would model the units as generating while light load studies would model the units as pumping.

Although the following discussion is based on the PSS®E platform, the approach is applicable to any commercial simulation software package.

Suppose we are studying a CPSH plant that has six units, as shown in Figure 5-1.

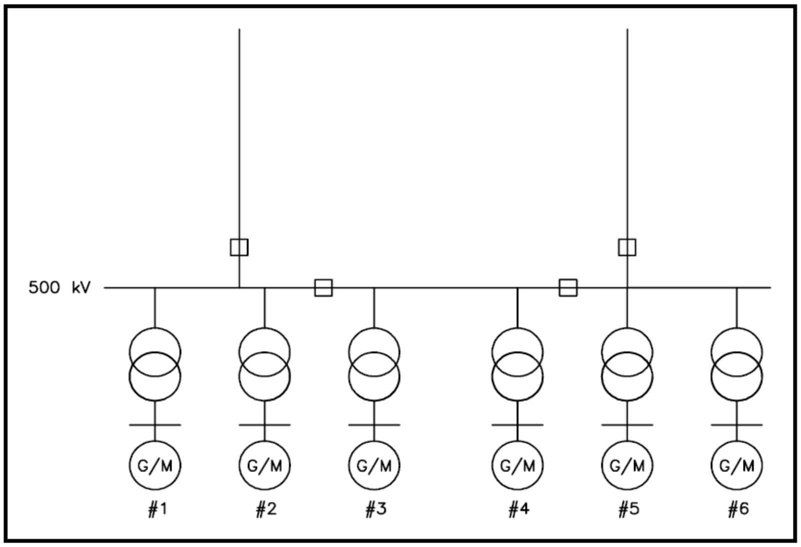

Figure 5-1 Electrical Configuration of the Plant

Since studies of both generating and pumping modes of operation are necessary, the load flow representation is created to handle both modes. It is convenient to represent each unit by two machines in the load flow and dynamic database, as shown in Figure 5-2. One machine represents the generating mode of operation, and the other machine represents the pumping mode.

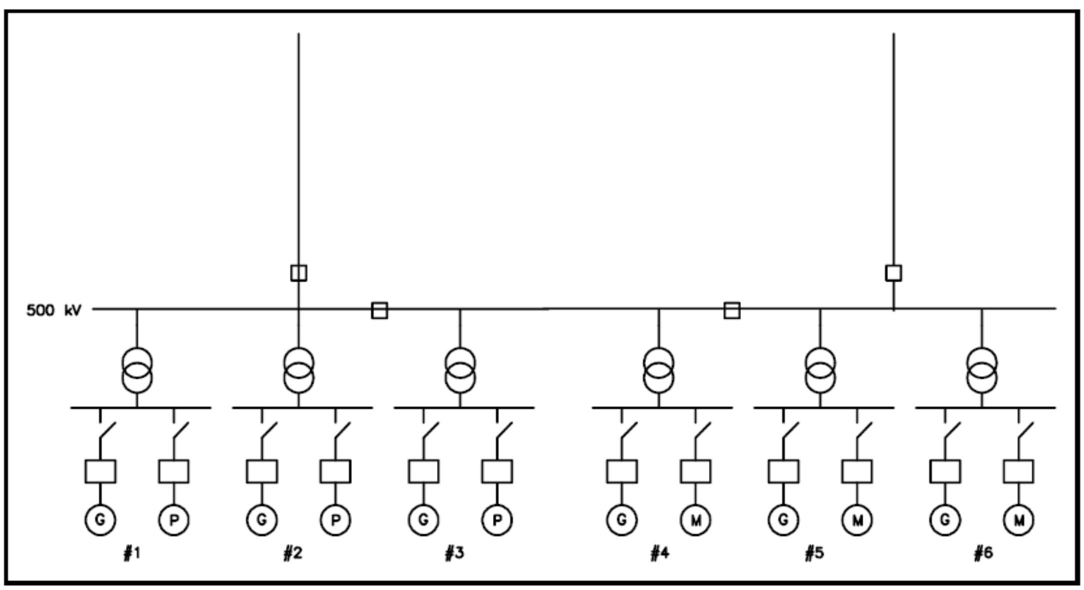

Figure 5-2 Plant Model for Electrical Network

Each of the machines is assigned a status parameter that allows the selection of either the generating or the pumping mode of operation. One can thus establish a load flow model to represent the generating conditions by turning “on” the machines that represent generators and turning “off” the machines that represent pumps. Using the opposite status will result in a load flow model for pumping operation. The dynamic simulation will recognize only the machines that are turned on in the load flow. Of course, only one of these machines can be online in a particular load flow case.

In the generating mode, the representation in the load flow case is exactly the same as that of a conventional hydro plant. During pumping, the electrical power consumed by the synchronous motor is negative in load flow.

The generator and pump can be represented by an identical set of generator and excitation system models. In PSS®E, the dynamic simulation models GENSAL, GENSAE, and GENTPJ are generally used to simulate the salient pole hydro machines. As described in Section 1, there are many models available to represent the excitation system.

For the generating mode of operation, one of the available hydro turbine-governor models may be used. The discussion in Section 2 reveals different features of these models. Sometimes the specific design of the plant may necessitate the modification of these existing standard models or the development of new, user-written models to represent pertinent details of this equipment. For example, if several units share the same conduit, the model logic should be able to take into account that some of these units may be uncommitted for the system condition being analyzed.

To represent the hydro units in pumping operation, the “governor” model for the motor must be different from the governor model used when generating. First, generally there is no speed regulation. The operator opens and closes the gates under manual control, and the gate position remains fixed. Second, the pump head is substituted in place of the static head. The pump head is a function of the water flow, as shown in Figure 5-3 for a unit rotating at rated speed. This pump characteristic can be characterized by a quadratic equation whose coefficients can be derived from pump characteristics provided in the specifications or determined by testing.

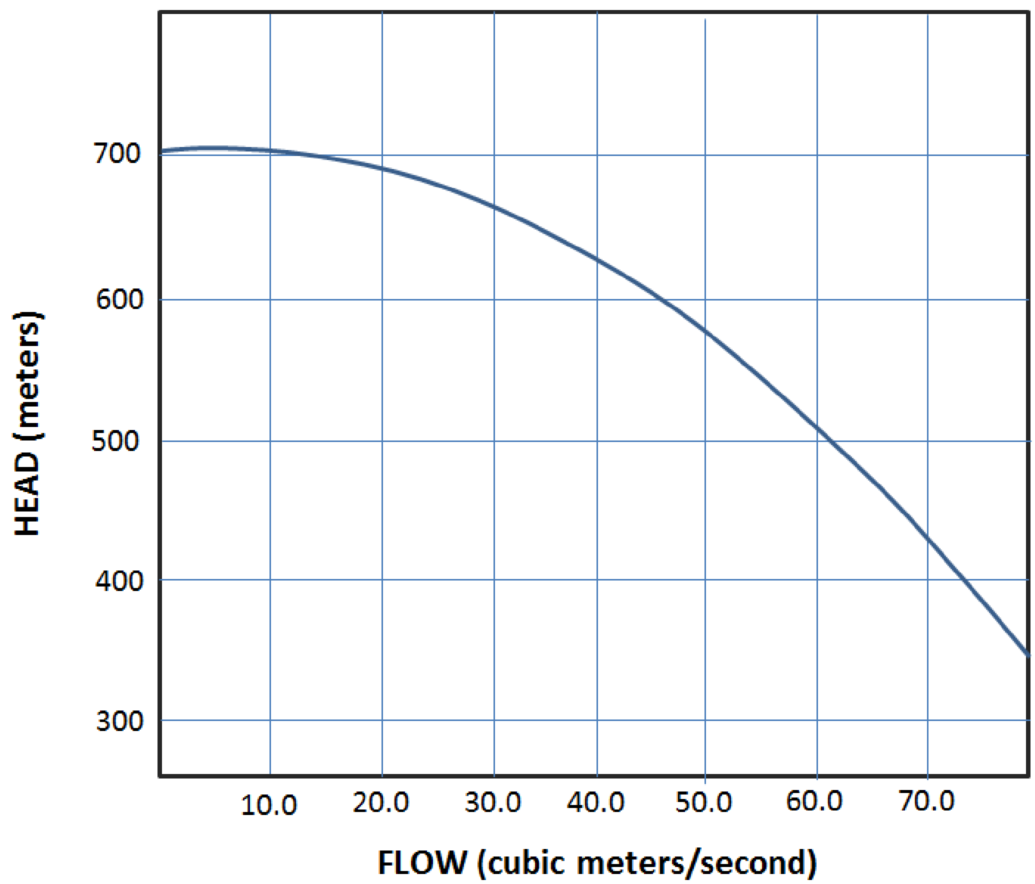

Figure 5-3 Pump Head Versus Water Flow

If speed deviations during transient conditions are noticeable, the flow, head, and power of the pump should be adjusted. The model allows adjustment per affinity laws proportionally to the speed, to the square of speed, and to the cube of speed, respectively, for flow, head, and power.

Mechanical power is calculated as the product of flow and head divided by efficiency. If sufficient data are available, look-up tables of flow versus gate position and of mechanical power versus flow can be represented in the model.

An example of the pump model is shown in the block diagram of Figure 5-4.

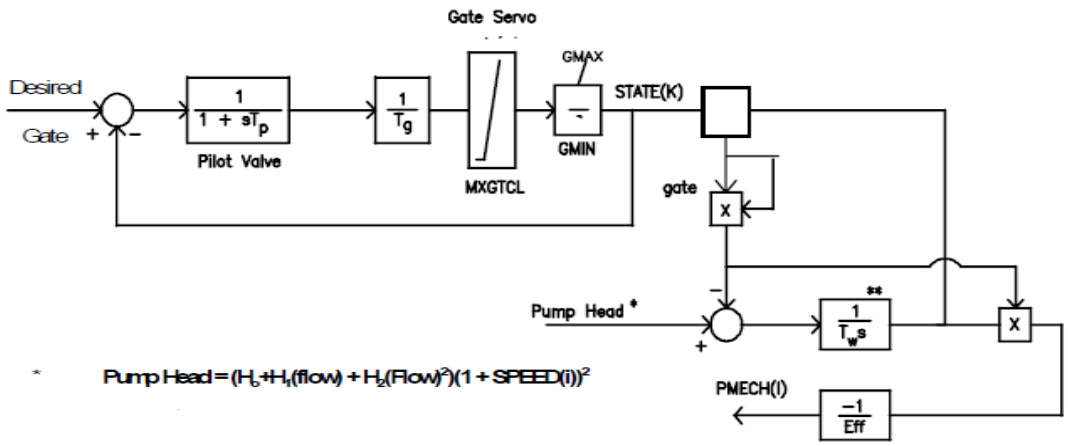

Figure 5-4 Block Diagram of Pump Model

The models and parameters for both the generating mode and the pumping mode of operation should be thoroughly tested. Such tests can be used to demonstrate some of the characteristics of the model that was just described. Regarding operation as a generator, one concern is the tuning of the speed governor. Usually, during this test (by simulation – not a field test), the plant is isolated and carrying a local load. During the governor test, the load is dropped by 5% to 10%, and mechanical power and speed responses are monitored. The plots in Figure 5-5 illustrate the governor test for a hydro plant with three units sharing the same conduit for the conditions where one, two, and three units are online. The difference in response is due to the difference in flows depending on the number of units that are committed, resulting in a change in the hydraulic characteristics. Similar tests can be performed for an increase in load.

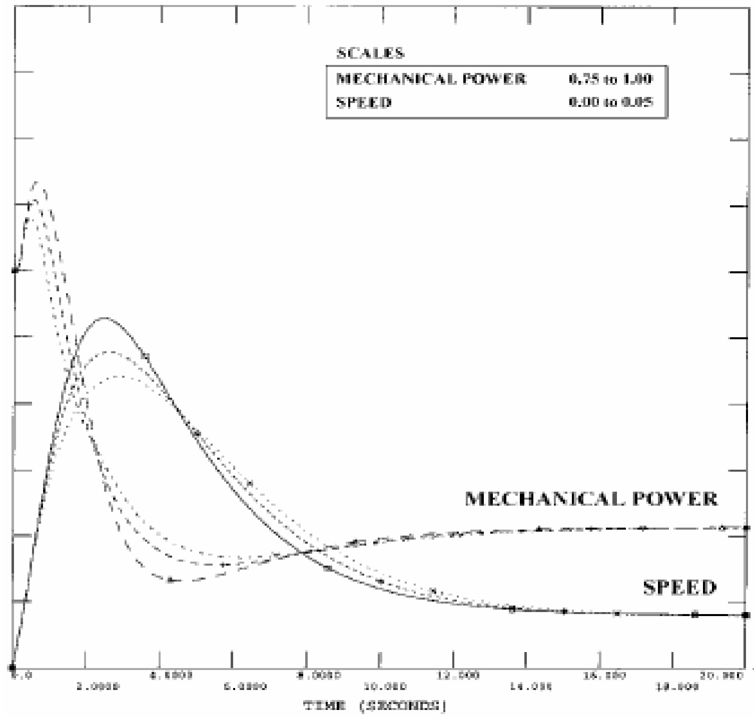

Figure 5-5 Comparison Plot for Different Plant Configuration for a 10% Step Change in Load

In the pumping mode of operation, the features of the CPSH plant mentioned above (i.e., three units sharing a common tunnel) also result in some peculiarities. The initial plant conditions for the test illustrated in Figures 5-6 and 5-7 were that one unit (Pump 1) was online at partial load and the second unit was also online as a synchronous condenser. During the simulation, the gates for the second unit were opened with a ramp that reached the fully opened position in 10 seconds. Pump 1 experienced a drop in mechanical power and flow during the ramping of the gates of Pump 2. The initial surge in the drop in flow and power for Pump 1 was due to the initial increase in the flow of Pump 2. Because of inertial effects, there was no immediate change in flow in the common tunnel. The sudden drop in flow in Pump 1 produced a higher pumped head, which partially restored the flow. The flow in the common tunnel increased due to the increased pump pressure from both units. After the gates for Pump 2 stopped moving, the flows, gate positions, heads, and powers settled at steady-state values.

This illustrates that the models for the pumped storage unit can be used to represent a wide variety of operating conditions.

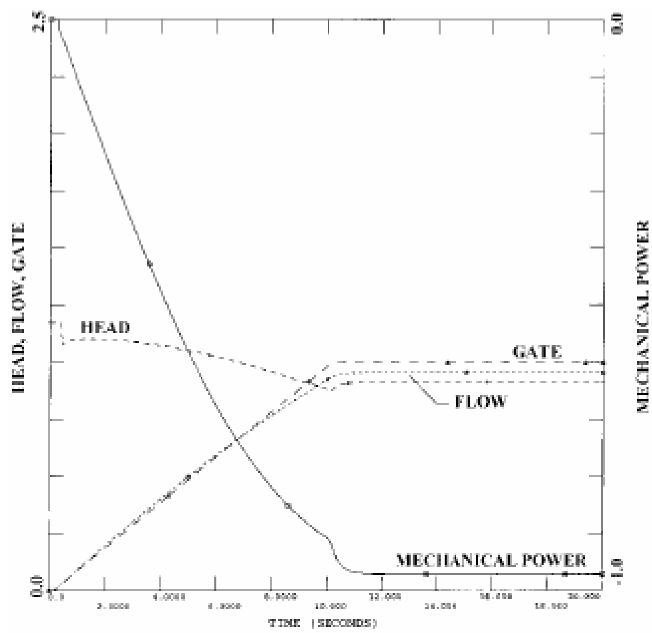

Figure 5-6 Response of Pump 2 during Startup of Pump 2

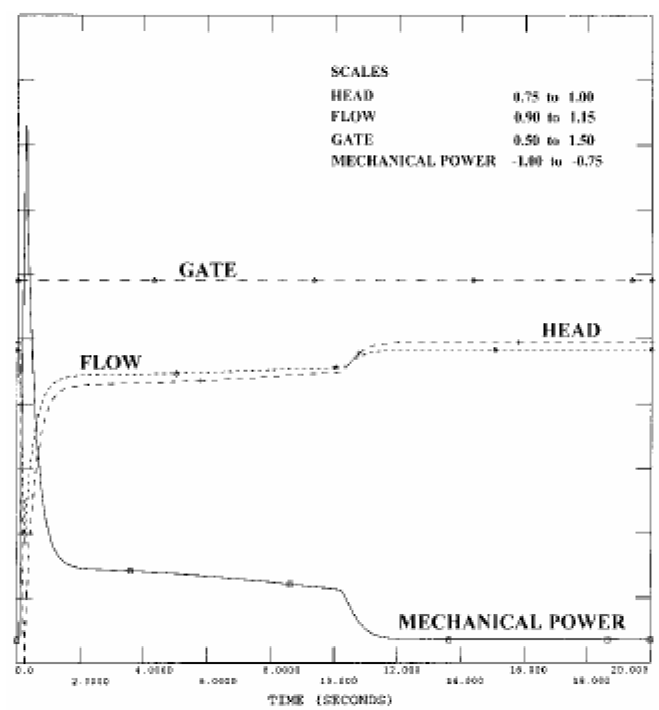

Figure 5-7 Response of Pump 1 during Startup of Pump 2

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