Modern Approach to Generator Stator Temperature Control on Load Following Hydro Generators

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ABSTRACT

Hydro generators in Alaska often experience great load swings while they meet the power and frequency control demands of small islanded systems. Stator temperatures can suddenly drop and cause condensation during these load swings if cooling water is not automatically controlled in a limited range.

This paper discusses the operational and technical aspects of converting a manual, penstock-driven cooling water system to a stator temperature set point-controlled system that utilizes pumps and control valves. The project had the following goals: flatten stator temperature swings without limiting the full rated range, reduce cooling water drive head and flow to thereby gain generation, increase stator life, and increase operator awareness regarding performance and stator life.

Specific Areas of Discussion:

• Project scope
• Operational considerations: stator temperature set point and allowable variance, condensation, training, SCADA integration, and backup system design
• PID control for steady state and rapid load change
• Unexpected control problems: valve actuation variable dead time and hysteresis
• Measured overall economic benefit

Note: To protect the client’s privacy, its facilities are referred to as Lake A and Lake B in this paper.
Introduction

The client's hydroelectric project is owned and operated by a power agency that also owns another hydroelectric plant. Both are part of an isolated power system that provides power to three communities.

The Lake A Hydroelectric Project is located at the head of Bradfield Canal, approximately 40 miles southeast of Wrangell.

The client’s project, Lake A1, is a natural lake used as a storage reservoir with 15 square miles of drainage area, 52,400 acre feet of active storage, and a normal water surface elevation of 1,396.0 feet at full pool. Unlike the second facility, Lake B, which is a dam, the project is a “lake tap” with an installed capacity of 25 MW. Water is conducted to the powerhouse through an intake from the lake into a drop shaft, through an 8,300-foot-long unlined power tunnel and a 1,350-foot-long steel penstock, which houses two generating units.

Approximately 70 miles of 138-kV transmission line (project is designed for 138-kV but operates at 69-kV) and 11 miles of submarine cable interconnect the Lake A’s project to two communities, and the facility is also connected to the electric system of a third through 57 miles of transmission line.

Two electrical substations and a switchyard are also associated with the project. The project began commercial operation in May 1984 and both generators at Lake A were rewound in 2010.

1 To protect the client’s privacy, its facilities are referred to as Lake A and Lake B in this paper.
Lake A's Operation

The Lake A plant is unusual in that it operates 100% of the time in isochronous mode. The hydro turbines there are responsible for maintaining the power system frequency at 60 Hz while the rest of the units on the isolated grid operate in droop mode. Normal operation of the powerhouse consists of running both units in isochronous load sharing to allow the two units to work together to maintain the system frequency. The Lake B units are operated as load following units and are automatically dispatched to allow the Lake A units to operate at less than their full power output to allow the isochronous units to respond to frequency upsets.

As a result of this type of operation, both Lake A units see a cyclic load profile with a ramp down to a minimum load during the evening/early morning and a ramp up during the morning hours. This load profile is generally the same with the minimum and maximum operating values determined by the total system load and the parameters of the automatic generation control system, which controls the generating units at the Lake B Plant.

With a rapid decrease in load and a fixed generator cooling water flow, rapid decreases in stator temperature were observed. This was due to the stator cooling water flow being manually set by the plant operations personnel to maintain a safe stator temperature when the unit operated at its maximum load. At lower loads, the cooling system components would become cold and cause condensation on the external piping and on the generator air coolers.

From an operation viewpoint, this was a concern for four reasons.

- **The first reason** was that the generator stator was being exposed to moisture due to the condensation on the air coolers at low loads. As shared in previous reliability sessions at HydroVision events, condensation was mutually agreed to be a primary consideration in decreasing the life of a generator.

- **The second reason** was that the generator stator was thermal cycling based on the load change. A minimum stator temperature that was observed was 20°C and a maximum temperature was between 40°C and 60°C, depending on the peak loads and cooling water inlet temperature. Thermal cycling is not considered to be a major concern.
for generator reliability, however, the industry as a whole does not have a lot of operational experience with thermal cycling the stator and the effect on the overall life of the generator.

The third reason was that the cooling water was derived from the penstock and that water could be used to generate power instead having the energy removed by two pressure-reducing valves and used as cooling water. Up to this point, the operators were manually setting the cooling water to approximately 150 gpm for each unit using a manually operated hand valve and the feedback from a mechanical flow meter.

A fourth reason, which is related to starting and stopping the units, was that the cooling water was not automated. This required the operations staff to turn on the water manually prior to starting a unit and turn off the water when the unit was shutdown. If the unit was not going to be shutdown for an extended time the operators would leave the cooling water “on” which would waste water and continue to cool the generator to below ambient temperatures, increasing the startup temperature swing. The reverse of this is that the units could not be without an operator manually sequencing the cooling water. Remote operation of the units was not possible.

Project Justification
The monetary justification for the cooling water automation project was based on two factors. The first factor was that the project would protect the investment made to rewind the generators in 2010. It was determined that the condensation problem was a major concern due to its potential impact on the operating life of the generator. Also factored into this was the belief that minimizing the thermal cycles over time would have a positive effect on the life of the stator coil insulation.

The second factor was that the lost energy due to the cooling water being derived from the penstock was more than the energy required to supply the cooling water from the existing cooling water pumps. This factor was looked at in more detail to verify the energy assumption.

A conservative scenario was used for this analysis. Each of the Lake A generator units already had a 10 HP cooling water pump installed, however, these were not used unless the penstock derived cooling water was out of service for maintenance. In addition, there was another 10 HP pump that could be used for either unit. In the analysis, it was assumed that these three pumps would be used to replace the cooling water used from the penstock. The total energy (kWhr) required for the three pumps for a year is calculated as shown below.

\[
\text{Total Pump } kWhr = \frac{HP \cdot 746}{Eff} = \frac{30 \cdot 746}{.85} = 26.3 kWhr
\]

Total kWhr/year = 26.3 * 24 * 365 = 230,645 kWhr/year

If the price of a kWhr is $0.065 (contracted power sale price), the yearly cost to run the pumps is approximately $14,992.00.
The cost of using the water from the penstock was determined based on what the energy would be worth if it was converted into kW through the turbine instead of being used for cooling water.

The equation shown below was used to convert unit head and water flow into kWhr for this analysis. Again, worst case conditions were used to ensure a conservative analysis.

\[
\text{Penstock Water kWhr} = \frac{q \times (H - Hf) \times \text{Eff} \times T}{11.8}
\]

Where:
- \( q \) = Flow Rate in Cubic Feet Per Second
- \( T \) = Time in Hours
- \( \text{Eff.} \) = Station Efficiency
- \( H \) = Gross Head in Feet
- \( H_f \) = Head Loss in Conduit System in Feet

Using the following parameters:
- \( q = 300 \text{ gpm} = 0.6684 \text{ cubic feet/sec} \)
- \( T = 1 \text{ Hour} \)
- \( \text{Eff.} = 90\% \)
- \( H = 1250 \text{ feet (minimum head at Lake A)} \)
- \( H_f = 10\% \text{ of} \ H \text{ or 125 Feet} \)

\[
\text{Penstock Water kWhr} = \frac{0.6684 \times (1250 - 125) \times 0.9 \times 1}{11.8} = 57.35 \text{ kWhr/total kWhr/year} = 502,406 \text{ kWhr/year}
\]

Assuming that a kWhr is again worth $0.065, the total cost of the penstock-derived cooling water is approximately $32,656 per year.

The net savings that could be realized by using the three cooling water pumps is approximately $17,664 per year.
Project Scope

The project to modify the cooling water system was divided into two parts. The first part was to complete all the mechanical modifications to the cooling water piping during an annual outage utilizing the plant operations and maintenance personnel instead of an outside contractor. This enabled the plant personnel to gain a better understanding of the system and allowed more flexibility in the overall project schedule. The cooling water piping was modified to meet the following requirements:

- Modify existing cooling water header to add a controllable on/off valve between penstock cooling water source and the common cooling water pressure header.
- Add individual on/off sequencing valves to each generating unit to allow the cooling water to be automatically turned on/off with the unit start/stop sequencing.
- Add a cooling water regulating valve to the outlet side of each of the generator’s cooling water piping. The ability to isolate the regulating valve and use a manual hand valve to control the cooling water was also part of this requirement.

The second part of the project involved the automation of the cooling water sequencing and the automatic control of the stator temperature. The second part of the project was combined with a larger automation project where the unit start/stop sequence was automated to allow single button start/stop for each of the generating units.

Cooling Water Control Development

The client chose SEGRITY for the cooling water control development due to its expertise with a wide variety of digital control systems and its familiarity with hydro control applications. The first step of the project was to define the operational requirements, which are listed below:

- The new system developed by SEGRITY allows operators to set a stator temperature setpoint from the existing HMI/SCADA system.
- Allowable variation in stator temperature feedback to be +/- 2° C through load changes with a steady state operational target of +/- 1° C.
- System integrates with existing unit control systems and existing HMI systems that the operators are already familiar with.
- System uses the installed pneumatic actuated control valve that was installed during Phase 1 of the project.
- A failure of the unit control PLC must not trip the unit or cause the cooling water control system to turn off the cooling water flow.
- System must be easy to use and intuitive to operators to minimize hours spent in training.

The control system design had several challenges because various components of the system already existed in the plant. These challenges are:

- The allowable variation (error) in the stator temperature was very tight; this required a control algorithm that closely matched the generator heating characteristics over the full operating range.
- The control valve that was chosen had a nonlinear porting configuration to allow a high turn down at low flows and a large porting at higher valve positions. While a better fit for the application, this valve required linearization in the control software and originally did not have an independent 4-20 mA position feedback.
- The stator RTDs were already wired to either the 300G generator protection relay or an existing Eurotherm temperature recorder.
The existing mechanical flow meters had not been calibrated since the plant was commissioned; the accuracy of the existing flow meters were unknown.

In addition to the challenges identified above, a larger concern for the controller development was due to the lack of documentation on the existing generator cooling system. As a result, the project plan for the cooling water system was developed to start with the automation of the cooling water flow control, which would allow testing of the unit to determine the relationship between cooling water flow and resulting stator temperature at different operating points. To ensure that flow was accurately measured, a new orifice plate flow meter was designed to replace the existing mechanical flow meter. The flow meter design included custom flanges that provided an exact replacement for the existing mechanical flow meter. The orifice plate was also custom designed to maximize the flow-sensing accuracy over the expected range of flows.

**Cooling Water Control Architecture**

In an effort to simplify the installation and support of the system, a remote IO node with independent manual controller was the desired hardware architecture. The remote IO node allowed the existing unit control PLCs to be expanded without adding more modules and cabling to an already full unit control cabinet. Not having to pull cables from each of the cooling water control locations also simplified (shortened) the installation of the cooling water control system. The figure below shows the main components in the cooling water control system.
Figure 5: Cooling Water Control Components

A backup manual controller was installed in the cooling water control enclosure. The manual control consisted of a small independent PLC that tracked the control valve position, and in the event of a unit control failure, the auto/manual relay will be dropped out. This would cause the control valve setpoint to be connected to the manual control PLC. Because the manual controller is always tracking the valve position, the valve will stay in the current location and can be opened/closed by an operator who uses the switches on the cooling water control enclosure.

The RTD feedback proved to be a bigger integration effort than originally expected. To fully integrate the RTDs, a Modbus Master was developed to run in the existing unit control PLC application. This Modbus Master polled the Eurotherm temperature data recorders every two seconds to update the generator stator RTD 3 through 8 values in the PLC. RTD’s 1 and 2 were wired directly into the PLC RTD inputs instead of being used for alarming in the 300G protection relay. An algorithm was then developed that would calculate
the average value of all the RTDs without adding latency to the hard-wired RTDs. This was done to ensure that the communication delays were not limiting the response of the temperature controller.

The HMI integration was completed by allowing the operator to visually see all the important cooling water system parameters as well as operate the cooling water system manually from the HMI display. The overall control allows the operator to select one of three modes of operation. The first mode is the most basic, and it allows the operator to control the valve position directly. This mode was used extensively when testing the actuator controller. The second mode allows the operator to manually set a cooling water flow setpoint from the HMI. This mode was used extensively during the initial testing of the cooling water controller. The third mode is the normal operating mode and allows the operator to select the desired stator temperature.

![Figure 6: Operator Interface for Cooling Water System](image-url)
Cooling Water Control Algorithm Development

The initial stator temperature control algorithm was developed based on a traditional PID utilizing an external feed forward. This type of controller is common in the process industry for dealing with systems that have long time constants such as temperature control. In this configuration, the PID controller acts as a “trim function” to correct any inaccuracies in the feedforward function.

**Figure 7: Initial Cooling Water Control Algorithm**

Unexpected Control Problems

To generate the data for the load to flow demand curves, the unit was tested at fixed MW loads and fixed loads to determine the resulting stator temperature. While performing these tests, it was observed that the stator temperature was nonlinear with respect to the operating point, indicating that there were other factors that affected the temperature. A more complicated feedforward function would be required to utilize the PID-based control. Another factor that showed up was that the actuator position response demonstrated variable dead times and hysteresis (setpoint error). These factors made it very difficult to tune the PID controller.

What was observed using the classical PID controller was that if the gains were adjusted for stable steady state temperature response, then the temperature offsets were large (+/- 10° C) during load changes. If the PID gains were tuned to adjust quickly during a load change, then the PID was unstable during steady state operation. This also resulted in large temperature oscillations that would cycle at the time constant of the stator temperature response (20 minutes). At this point, SEGRITY decided to address the two problems separately and engage Jack Schade, who is an expert in developing modern control-based algorithms to address these types of challenges.
Actuator Response

The first problem to be addressed was to improve the actuator response. The initial valve response trend shows the valve position response to a setpoint step. It was observed that the valve exhibits both a variable offset and deadtime as a function of error and also operating point (current position). This resulted in the valve not having the accuracy required for stable steady state control.

To address this problem, a nonlinear model of the valve dynamics was developed from the test data. This valve model was then validated to reasonably match the actual valve response and was then used to develop a modern controller for the valve. It is important to note that dead time and hysteresis observed in the valve stroke control are due to the static friction in the valve/actuator itself and the compressibility of the air used by the mechanical valve position controller that is integral to the valve position actuator.

Two different nonlinear valve position controllers were developed to see which control method resulted in a controller that was robust to changes in the valve/actuator dynamics. The robust requirement is important because the solution must be capable of operating even if the valve/actuator dynamics change over time. If the controller did not exhibit a high level of "robustness," then the controller would need to be retuned anytime the valve/actuator was replaced or the dynamics of the system changed (actuator/valve mechanical wear). Retuning the controller is undesirable because manually retuning the controller would only guarantee the loop to be stable as long as the valve/actuator continued to behave the same way. If the dynamics change, then an additional "retuning" would be required.
The two types of controllers considered were a nonlinear controller utilizing shift register-based deadtime compensation and a nonlinear controller utilizing a PADE deadtime approximation. The controller based on the PADE deadtime approximation was determined to be the most stable over a wider range of dead time and hysteresis variation. The new nonlinear actuator controller was implemented and tested at site. The response was found to be favorable throughout the full operating range of the valve actuator. A block diagram of the nonlinear actuator controller is shown below in Figure 10.

The actual valve response is shown in the hysteresis chart below. The hysteresis data showed that the valve was still difficult to control below 8% stroke. Also, there was an area around 60% stroke where the valve was still observed to “stick” when it was slowly ramped. This sticking was not observed when the valve was “stepped” at this same point, which indicates that the observed deviation was due to dynamic friction. When the valve was opened above 80%, a small offset between the setpoint and feedback became evident. This offset was not significant enough to cause control issues. This value became more pronounced at 100%. It is expected that the observed response will change over time as the actuator/valve wears.

![Figure 10: Updated Valve Position Control w/ PADE Dead Time Approximation](image)

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Figure 11: Valve Control Hysteresis and Actuator Step Response

Stator Temperature Controller

Once the valve position control was performing reliably, improving the stator temperature control algorithm was the next step to developing the final stator temperature controller. A statistical design approach was used to derive the necessary data for the temperature controller.

Utilizing derived data and applying statistical control development techniques, a reduced-order controller was developed. The final control algorithm that was implemented is shown below.

The basis for the generator stator temperature control algorithm is a generator cooling function that is based on the ability of the air coolers to remove the heat from the generator. For every iteration of the controller, the cooling function is evaluated, and the correct amount of cooling water is determined to control the stator

Figure 12: Final Generator Stator Temperature Controller Block Diagram
temperature to the setpoint. The controller has a convergence function in the Flow Correction Calc block to integrate out any errors between the actual required cooling function and the calculated cooling function. This correction function ensures that the stator temperature converges to the desired setpoint even if the cooling function is not exactly correct for a given operating point.

The main challenge throughout the development of the controller was due to the lack of sufficient design data and test data to determine an accurate system model. The knowledge of the system is required to develop the overall controller as well as to validate the controller once it is determined. In this final implementation, the bandwidth of the Flow Correction Calc function was increased to allow a reasonable convergence to the setpoint during steady state. As will be shown later in this paper, the increased bandwidth contributes to an overactive actuator. Because the stator temperature was capable of being controlled to the setpoint, further improvements of the controller were deemed to be out of scope for this project.

**Stator Temperature Controller Response**

The stator temperature controller response was found to meet the original requirements as displayed in the seven-day trend of stator temperature and unit load shown below. The average stator temperature is capable of being controlled to within +/- 2°C of the setpoint except when the unit is shut down. During steady state operation, the variation was found to be mostly within the desired +/- 1°C band around the 75°C setpoint. And always within the +/- 2°C.

![Stator Temperature Control Response – 7-Day Period of Operation](image)

As observed in the above figure, the stator temperature continues to cool down when the unit is shut down, however it is shown to quickly control the stator temperature to the setpoint on a subsequent startup with a small overshoot of + 3°C.
Measured Overall Economic Benefit

The overall economic benefit for maintaining a constant stator temperature is difficult to calculate due to the lack of industry data on the real impact of condensation and thermal cycling on the life expectancy of the generator components.

A real short-term monetary impact can be estimated based on the reduction in energy consumed to provide cooling water. What is known today is that it takes significantly less cooling water to maintain a constant stator temperature of 75°C than originally expected. This flow demand is typically met by using one pump per unit, which reduces the overall energy required to cool the units by 10 HP. If the original energy cost estimates are updated to include the third pump running 50% of the time, then the cost of running the cooling water pumps is a savings of $20,163 per year.

Note that the monetary value due to a reduction in energy usage will be offset by the increased cost of maintaining the cooling water control system. A key consideration is that the metering valve/actuator will need to be replaced periodically. The current cost of replacing the control valve and actuator is approximately $3,500 per valve. If the control valves were required to be replaced every five years, the increased cost of maintenance would still be significantly less than the estimated savings for a single year of using the pumps.

A detailed monetary analysis would also include the upgrade costs of the PLC hardware, maintenance on the cooling water pumps, and other controller components. This level of economic analysis was not done as part of this project as the primary reasons for doing the project were to stop the condensation and to automate the start/stop of the units.

Lessons Learned

This project started out as a straightforward cooling water automation project, however, due to the tight control requirements and components selected, additional work was required to meet the system requirements. Some considerations for developing a system in the future are:

1) Use an electrically actuated control valve instead of pneumatic. This will eliminate most of the positioning problems related to the pneumatic actuator and high valve friction.
   - The development of the nonlinear actuator controller added further expenses to the project due to the additional algorithm development time.
2) Instead of using an orifice plate flow meter in front of the valve to measure flow, use a characterized control valve and use the differential pressure across the valve to calculate the flow through the valve. This flow control technique is used extensively on high performance flow controls associated with gas turbine fuel control where pressure drops in the fuel system must be minimized. This would eliminate the pressure drop of the orifice plate, which will further decrease the amount of energy required by the system.
3) Bring all the RTDs into the control PLC instead of using communications to an independent device like the Eurotherm. This added integration time created a reliability issue and creates long latencies on the stator temperature feedback.
4) Implement an independent data acquisition system to ensure that all required data is acquired to do the necessary development and validation work. Issues with the existing plant historian prevented long-term test data from being collected and is still an issue with this plant.
Project Results

The main result of this project was to automate the generator cooling water control and achieve virtually flat line response in stator temperature as the unit followed the load.

A second success was that it was demonstrated that statistical control techniques can be applied to these types of problems even when limited data sets are available or the data sets are questionable.

An additional success was the development of an algorithm based on modern control techniques to resolve the classical issue of actuator sticking without having to tweak and tune the controller.

The estimated net savings in energy dollars was over $17,000 per year.

The final system was designed to be intuitive and easy to use to minimize the number of training hours that must be invested in supporting it.

Future Development Work

The controller cooling function is not fully optimized to match the dynamics of the actual stator temperature system. The existing control algorithm is designed to allow the controller to automatically adjust to variations in the stator cooling power relationship. Because of this, the overall integral gain of the controller is higher than it could be. This higher gain results in an over-active control valve, which causes it to go through two to three cycles of oscillation every hour. The valve response was added to the original stator temperature response chart for reference below.

![Figure 14: Stator Temperature Response with Valve Position Feedback Shown](image)

The valve response shows that the controller “hunts” when controlling the stator temperature and the load is decreasing. This is because the cooling power prediction is not accurate throughout the full operating range. This results in the Flow Correction Algorithm causing the controller to saturate on a minimum cooling water flow limit. The temperature controller still maintains the stator temperature, however, the valve is observed to oscillate more than it needs to.
Additional work is needed to determine the right data and how to collect it to optimize the existing controller. During this project, statistical methods were used to derive the system model and the controller directly from recorded data. These techniques would require more work before they would deliver an optimum solution. Additional research could also be done to utilize machine-learning algorithms to automatically generate a system model that accurately reflects the dynamics of the system. This issue is further highlighted in the figure to the right below.

The red data points were derived from the original generator testing, which was documented during the commissioning of the original unit.

The blue data points were derived from the physics-based model that was developed for the generator cooling system and stator heating. This shows a high correlation in the response to generator output, however, there is a large offset that is not explained.

The green dots show the stator cooling power that was derived from the onsite load/cooling water flow testing. This data showed that there was very low correlation to the original test data and the data from the physics-based model of the system. This lack of correlation was a surprise because it showed that the method used for deriving the relationship between the stator cooling power and the generator load did not produce accurate results when the data was derived from onsite testing. This could be an indication of a data acquisition issue or lack of a statistically significant sample.

The cooling water valve/actuator position controller could be optimized for use on units that experience “Sticky Wickets.” Today the main option is to “tune” the controller response separately in the “sticky” area or avoid this area during normal operation. With a robust wicket gate-positioning controller, the controller can automatically change its dynamics to adjust to the changes in positioning accuracy.
Conclusion

A generator cooling water control system was developed to maintain the stator temperature within a tight band independent of the operating point or operating load changes. This was developed for a load following unit on an isolated power grid to minimize thermal cycles and condensation on the generator coolers at low power outputs.

Several challenges were overcome using modern control techniques to develop a new technology for both actuator control and cooling water control. These techniques can be further refined and applied to other applications.

The economic justification of the cooling water automation project is difficult to quantify due to the lack of data regarding the impact of thermal cycling and condensation on the life of the generator stator. Condensation has been generally accepted as a contributor to reduced stator life, however, very little information is available on the impact of thermal cycling. While this project was focused on a unique operating situation for a hydro turbine, load following is becoming more common as hydro units are cycled in response to the integration of renewable energy.

References


Biographies

James Volk, P.E., PMP – VP of Engineering at SEGRITY LLC

James has over 25 years of experience developing and maintaining mechanical, analog, and digital turbine governors in hydroelectric plants. He is the founder and VP of Engineering at SEGRITY where he is responsible for developing the next generation of hydro turbine governors that meet modern performance requirements.

James has also worked for major hydro-focused companies like General Electric and Woodward Governor Company.

Eric Wolfe, P.E. – Director of Special Projects at an Alaskan Power Agency - USA

Eric has over 20 years of mechanical and civil engineering experience working in the hydro-utility business. His utility experience includes QA engineering on large hydroelectric construction projects, hydro operations engineering, and project management. He also has extensive knowledge on and experience in hydro-machine testing including turbine and generator performance, machine vibration response, and machine shutdown characteristics. He has been project manager for development, and implementation of hydroelectric monitoring and optimization systems. He brings valuable hydroelectric utility planning, operating, and rehabilitating experience to his employers. As a planning analyst, Eric determined electricity buy-sell quantities for the day ahead and term markets, and optimized reservoir release schedules. Working for an Alaskan Power Agency, Eric provides strategic planning, short- and long-term system planning, and acts as project manager for capital projects.
Jack Schade – Control Systems Analyst – Independent Consultant - USA

Jack held positions of Engineering Manager, Electrical Engineer, Engineering Consultant, and Control Analyst since 1971 when he worked for the Woodward Governor Company. Since retiring from Woodward, Jack has worked as a consultant to the turbine control industry. His current interests are researching ways that modern machine-learning algorithms can be applied to solve modeling and control problems that historically required extensive physics-based modeling and verification. He is looking for ways to use the large data sets, which can be easily generated from operating turbine/generator units, to develop accurate system models and control algorithms.