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Evaluation of Model Based Control System

The power generation industry has introduced the first generation of Control Systems that set operation levels of plant equipment by "interpreting" and "adjusting" operation based upon real time plant data. The new active real time engine simulation controls are stated to be able to assess unit health and make adjustments as the software interprets the operational data. There is little documentation in the field, and even less plant knowledge, on this development which makes this proposed evaluation effort a compelling task to fill that void. Essentially, this is the first generation of low level artificial intelligence employed in a control in the power industry. What hangs in the balance is the impact on hardware integrity if the new control methods do not function as expected on the high end, and the impact on the generation economics for plant ownership on the low end.

What does the model based control do and how does it act? This has not been studied, yet these control methods are now a standard in controlling the latest technology turbines. The Speedtronic control has had a 50 year evolution. A short background review illustrates the ever increasing complexity of its evolution.

History of the GE SPEEDTRONIC Mark Gas Turbine Control Systems series

The first electronic solid state control SPEEDTRONIC Mark I began operation in plants in 1968 offering automated turbine control, protection, and sequencing. Less than 8 years later the Mark II integrated circuit model was introduced, followed two years later by the Mark II ITS (sometimes referred to as Mark III). This third iteration had Integrated Temperature System (ITS) and was not widely sold. These early versions were analog systems.

In 1982 the Mark IV was released providing an all-digital integrated control system. This was widely installed for ten years until the Mark V was released. Triple redundancy - Triple Modular Redundant (TMR) - was introduced in this model and continued into the Mark V and Mark VI.

The GE SPEEDTRONIC Mark V was introduced commercially in 1993 as a 2nd generation and more advanced digital implementation with microprocessors. The Mark V continues to function well in many plant installations. The system controls are limited to the turbine and do not integrate with other plant equipment. This limitation underscores the importance of diligent monitoring of the impact of each component on the overall plant performance.

The Mark VI and the more recent VIe have been the General Electric OEM turbine control system since 1999 and 2006, respectively. The Mark VIe distributed control system is the current state-of-the-art

OEM turbine installation and can be retrofitted to upgrade previous Mark generations and systems of other manufacturers. The Integrated Control System (ICS) incorporates the HRSG and Steam Turbine of combined cycle applications through a BOP (Balance of Plant) management of plant components, both for OEM and other manufacturers. There is the flexibility of simplex, dual, or TMR redundancy on a distributed control platform. The software incorporates model-based control scheduling.

The major change that operators experienced going from the MKVI, which was open logic, to the MKVIe, is the "black box" containment of the macros that are not accessible to plant operators without OEM password permission. The model based control is one of the black box macros and, as a result, only the OEM knows how it operates.

Model Based Control

Figure 1 shows operation with model based control sample data indicating a wide variation of exhaust temperatures from the initial commissioning settings. In theory, it is the control system that has interpreted real time data and made a "decision" about where the unit should operate.

This is contrasted with the traditional style 7FA compressor pressure ratio (CPR) based curve or array lookup which shows a consistent straight line with stable control operation points. This correlation relies on the relationship of the operating CPR of the turbine to set an exhaust temperature target. The control then operates the fuel control value to achieve the target exhaust temperature. A known consequence of the traditional style control is that it has undershoots and overshoots in firing temperature due to the control not knowing specific shifts in performance of the turbine. These performance specifics change over time, or even from day to day in the case of fuel properties. These changes provide a legitimate justification for an active real time engine simulation or model based tool.

However, there is the need to understand and verify what the control is doing in order to better comprehend what might be happening to the HGP relative to the intended rated firing. On the one hand, this is important for hardware integrity (life at rated operation) , and on the other hand, this is important for the assurance that the unit has revenue producing generation and the right amount of energy available for Combined Cycle (CC) operation at expected economic operation.

Firing temperature overshoots and undershoots are known to occur from performance shifts or changes in exhaust pressure or fuel properties. These misalignments are due to turbines still operating under commissioned level control schedules after component wear and degradation. Typically, a unit first loses compressor flow and efficiency and then as the turbine continues to age, the turbine inefficiency occurs which is believed to offset the compressor derived overshoot. These effects are discussed later.

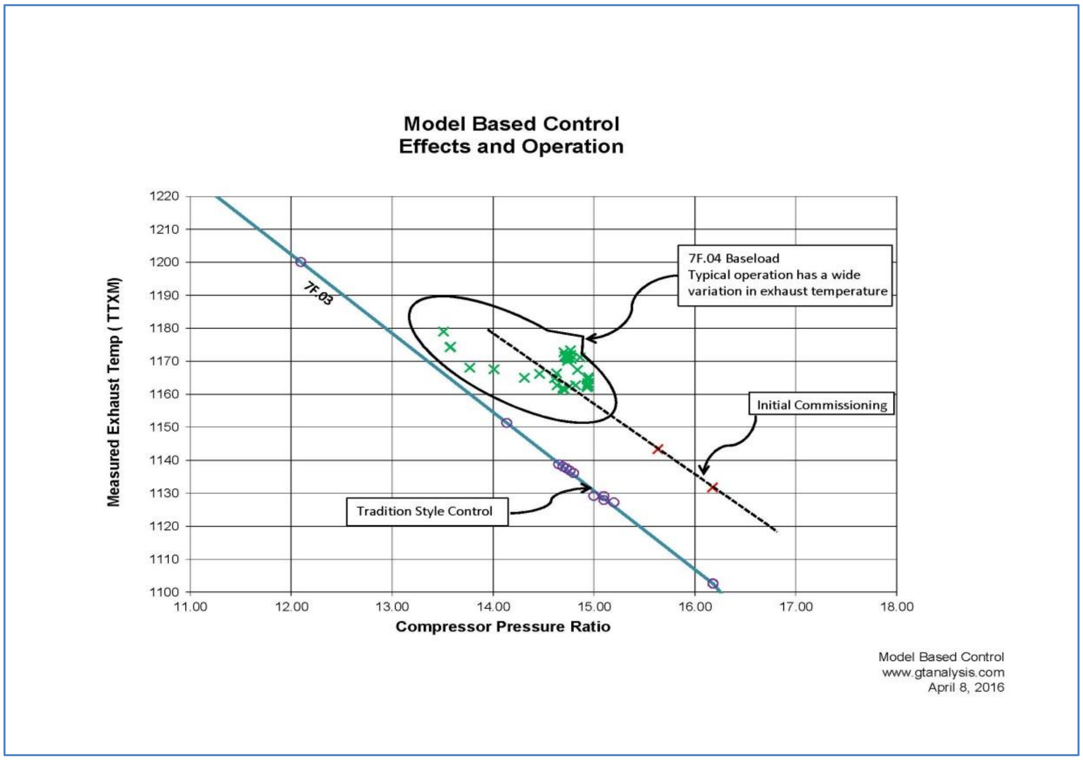

Figure 1
Control Schemes and Setting Variations

Figure 2 shows a more detailed breakdown, year-by-year, of the same sample of operational data. There is a large variation in exhaust temperature for the model based control. At the top end, a 10°F higher exhaust setting from the initial setting is observed. At the lower end a -18°F exhaust temperature setting from the initial setting is observed.

Upon first look this variation is significant, and when considering the performance effects, one would conclude significant changes are occurring in the model based control algorithm as compared to traditional control. Maybe this data represents an actual interpreted change in the turbine performance. But can the operator verify if the control response is justified?

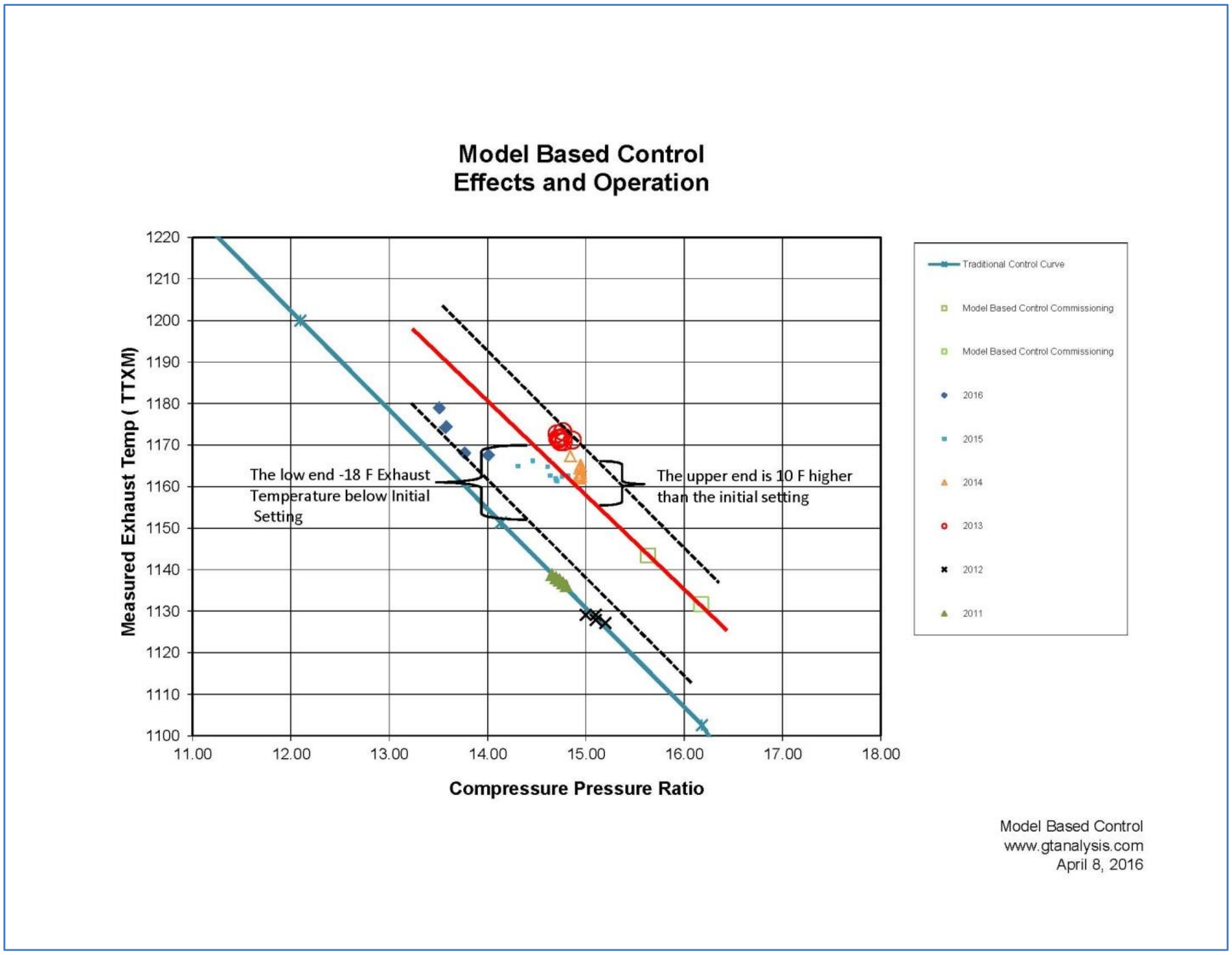

Figure 2
Degradation Impact of Model Based Control

Operationally, if the model based control system is not correctly interpreting and/or responding to a performance change, then the turbine would overfire by 20°F at the upper end. That could certainly cause hardware damage. On the lower end, a -18°F lower operation is observed. That equates to a 40°F underfire. If the underfire isn't a result of hardware component changes or a performance effect shift at the low end, then the underfire results in a negative economic position for plant ownership.

This variation in performance data illustrated in Figure 1 and 2 is beyond what the standard control method has historically allowed. Unless this turbine has had a justifiable performance shift, the model based control may not be operating as expected.

Traditional Effects on the Control

Operational effects from performance shifts, fuel shifts, and inlet and exhaust losses are well known. However, this is an area often not considered as causing operational concerns to the gas turbines. Additionally, if a plant does not complete compressor water washes when indicated, there can be a significant impact on advancing erosion, and therefore, on generation.

Some of these performance factors are recoverable, but others are not recoverable. As this lost performance effect accumulates, a traditional control method will have the under and overshoots in firing temperature. So then, how does a model based control handle the assessment and adjustment in firing temperature? This is the question to be addressed in this project.

Typical operational effects of performance or operating changes are listed below.

Inlet Filter Loss

An increase in inlet filter loss would typically increase the firing at a rate of +2.3°F per every increase of 4 inches H_2O.

Compressor Flow Loss

A decrease in compressor flow loss would typically increase the firing at a rate of 2.9°F per every 1% loss. Normally, flow loss can easily reach 2%, and if there is no procedure to identify the need for water washes, then even 5% or more can result. This substantial impact is then magnified by a potential 5 X ~3 = 15 degrees of overfire.

Is the new model based control smart enough to adjust for the flow loss and better yet indicate to operations that there is a flow loss?

Barometric Pressure Error

The potential for error from a barometric pressure transmitter issue is quite high. When considering altitude variation is on the order of 10%, a mis-calibration or measurement error can easily produce a 50°F overfiring effect.

Compressor Discharge Pressure Error

Compressor discharge pressure also factors into the pressure ratio. The variable can be most readily observed on domain of the control scheduling for a traditional curve. An error in a transmitter can cause an erroneous control setting. Additionally, it would cause extreme errors in performance calculations.

1st Stage nozzle area

A change in 1st stage effective area would overfire the turbine. The typical control scheduling off of the turbine exhaust temperature is a negative slope because a lower compressor pressure results in setting a higher exhaust temperature.

Turbine Efficiency Change

Turbine inefficiency can occur through degradation or hardware changes during an outage.
Turbine efficiency has a strong impact on firing temperature, but unlike the compressor fouling, is a slower degradation characteristic. Typically 1 point loss in turbine efficiency can cause an underfire of -18°F.

Exhaust Pressure Loss

For every 4 inches of exhaust pressure loss, an adjustment of exhaust temperature setting is normally needed on the order of +2°F to maintain the same firing. If the adjustment is not implemented an underfire of about -4°F would be realized.

Exhaust back pressures usually rise over time on HRSG's with degradation. In the case of CC operation it is not be unusual to see an 8 inch increase of water pressure loss.

APEX of Firing from Degradation

In the early years after commissioning typical degradation tends to occur in the compressor with a higher rate of recoverable loss from fouling through washes. As time advances, non-recoverable and permanent erosion occurs in the cold section. The deterioration in the compressor results in a higher firing overshoot to the point of the highest overshoot. This peak, or highest point of overshoot, is the apex of firing resulting from degradation. Consequently, the hot section components begin to degrade and erode. The turbine inefficiency then becomes a dominant contributor and drives firing downward. The turbine inefficiency causes the turbine to underfire. The operational effects are counter compensating after the apex of degradation. One performance shift negates the other.

The important question is, can the new model based control detect all types of performance shifts over time and does it then make the proper adjustments? An evaluation period needs to be long enough to capture the complete set of performance characteristics.

Proposed Research Project

This proposed research project installs GTAnalysis's Precision Monitoring software on a supplied or existing server that will run in parallel to an advanced gas path turbine Mark VIe control system. The software tool will collect and calculate internal performance and store on a database. The internal performance will be analyzed against the Mark VIe control interpretation of real performance shifts over the time period. The control setting changes will be verified and compared, and a report will be produced.

The time period of execution is 2-3 years. The intent over time is to collect enough performance data that represents degradation scenarios out past the apex of firing caused degradation.

Preferred Testbed

A natural gas fired plant with a 7F.04 turbine that has newly installed AGP hardware and compressor enhancements, and a MKVIe control system with the Model based active real time engine simulation.

NDA

A Non-Disclosure Agreement will be executed by all parties to protect the proprietary nature for all parties.

Deliverables

For first 6 months of the first year there will be quarterly reports.
Subsequently, reports will be submitted on a monthly basis.

A final report summarizing findings with analysis of monthly data evaluation, relevant plots, and with conclusion and recommendations will be submitted at the end of the project.

PROJECT COMPLETION

At project completion the GTA supplied server and/or the GTAnalysis, Inc Precision Monitoring software will be removed from the site and returned to GTAnalysis, Inc. Should the plant wish to continue with the monitoring software they will enter into an agreement directly with GTAnalysis, Inc.

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