VALUE OF HIGH-RESOLUTION DATA IN PRODUCTION ENGINEERING

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ABSTRACT

Today, a good upstream or production engineer must understand the running condition of every well of which he is in charge in order to optimize production & profitability, usually by adjusting various setpoints. Typically, he will use data recorded by a pump-off controller (POC), fluid level shots, etc. as well as often coupling this wellhead-level data with intermittent information from stock tanks or test batteries.

To make things more complicated, most of the data generated by sensors on a field stays on the field controller's local memory with just a select few data points actually transmitted (via low-bandwidth SCADA) to a host server and made readily accessible to engineers. Typically, this system is just capable enough to allow an engineer to diagnose crude issues and major failures. More modern systems send data to centralized control rooms far from the field, almost always unstandardized and unsanitized – as a result, more data sent means more man-hours needed to actually parse and analyze it which often falls by the wayside. In addition, it is often impractical to fully instrument a field with traditional automation solutions given the overwhelming infrastructure required and installation burden. As a consequence, most operators rely on incomplete data, leading to significant inefficiencies along with high operating costs.

In this presentation, we introduce state-of-the-art developments, both in terms of hardware technologies and mathematical data processing techniques used to automatically interpret data, as well as how these developments effectively leverage data points across the field to (1) reduce the cost of monitoring assets by an order of magnitude, making it affordable for lower flow legacy wells, (2) remove the need for routine in-person inspection of leases, and (3) increase production and equipment life-time while reducing power consumption through optimization.

A NEW FRONTIER IN OILFIELD AUTOMATION SYSTEMS

Traditionally, oilfield automation has been the territory of complex, often limited, but very expensive automation and telemetry systems. Indeed, controllers on the market typically must embed significant processing power in the form of expensive ruggedized industrial computers, thus inflating hardware costs. Installation is also a significant burden, involving significant electrical work, and often requiring that heavy equipment be brought on site to dig trenches and bury wires. These systems are usually the product of a long history (as many modern rod pump controllers are direct heirs to the pioneering work of Sam Gibbs), involving much sophistication in instrumentation and data processing (for instance in the form of the modified wave equation for rod pumping), but very little in terms of actual control algorithms and self-supervisory capabilities. As a result, while they are great tools for data acquisition and performing basic control logic, they often require constant, tedious supervision – considerable fine tuning and oversight by engineers – to perform optimally.

Simultaneously, communications have historically been a challenge in remote locations where most oil and gas producers operate. This has led to the adoption of solutions such as SCADA setups relying on custom radio systems to retrieve instrumentation data and, sometimes, control the assets remotely. Unfortunately, these systems require significant infrastructure investment and maintenance. They have also become infamous for their very low polling rates. In the context of rod pumping, it is common for operators to be forced to optimize their wells based on a couple of dynacards transmitted each day, while in-depth troubleshooting might require sending a technician on location to physically retrieve the limited history stored in the local memory of the controller.

Combined, these two challenges have dramatically held back the potential benefits from automation in the oilfield. Indeed, in our experience it is rare to see any kind of automation on wells producing less than 10 or 15 barrels of oil a day. Even on larger assets whose production justifies the significant cost and operational complexity of adopting some of these legacy solutions, there is a pressing need for more automated optimization and supervision of existing controllers. While the idea of creating a *digital oilfield* has widely been discussed in the industry for two decades now, there is still a significant gulf between where we are today vs. where we *can* and *should* be.

In this context, several revolutions have taken place that transform the perspectives of oilfield automation:

- The advent of reliable, long range cellular networks is on the brink of offering a solution to the connectivity issues experienced in the industry, thus removing the need for any custom telecom infrastructure. Leveraging those newer long range, low bandwidth networks (5G networks today, satellite constellations tomorrow) requires a great deal of sophistication in data processing and compression, but continuous, high-resolution instrumentation data streaming is now within grasp (for instance, providing all rod pump dynacards at stroke-by-stroke resolution)
- By unlocking two-way communication channels, these new networks allow for a much greater leveraging of cloud systems. As a consequence, many painstaking computations can be offloaded to the cloud while tailored, light-weight AI models generated at great computational cost, but cheaply run, can be pushed back to edge devices. This allows lightweight, microcontroller-based hardware to replace even the most powerful and sophisticated systems, thus collapsing hardware costs.
- By making high resolution instrumentation data available in real-time in a clean format, data-intensive AI algorithms can be deployed to supervise and optimize operations. In this paradigm, computational resources cease being a barrier to implementation. Another benefit often overlooked is that data from a given set of equipment can readily be augmented with information coming from other parts of the field. A straightforward example of this is the systematic pairing of wellhead and tank data to optimize production in real-time.

Acoustic Wells strives to make the best use of all those windfalls to provide breakthrough fieldwide automation solution.

CASE STUDY 1: STROKE-BY-STROKE FILLAGE ANALYSIS FOR ROD PUMP OPTIMIZATION

Using 5G networks and advanced on-device compression algorithms, our system is able to stream continuous, very high resolution (> 100 Hz) data back to our centralized cloud system, including well-head position and rod pump loading. Using these signals, our system automatically generates dynacards for every single stroke of the pumping unit. A machine learning algorithm then automatically processes these cards to generate pump fillage results and diagnose mechanical issues. This stroke-by-stroke data is extremely valuable as far as our system's capability to diagnose and optimize around complex well behaviors as well as audit and improve controller outcomes.

In this first example, we consider the case of a VFD-controlled rod pumped horizontal well drilled & completed in 2015, 4,500 ft TVD with a 5,500 ft horizontal section. Field operators reported highly inconsistent pump behavior backed by Echometer dynamometer surveys displaying full and empty stokes a couple hours apart (see Figure 1). Despite their best efforts, the operators were unable to optimize the well to suppress this behavior.

Upon installing Acoustic Wells' continuous monitoring and optimization system, it became apparent that the well was experiencing severe slugging behavior. Slugging is an adverse flow pattern that can emerge in bi-phasic gas-liquid flows in presence of altitude changes of the flow conduit (pipes, risers, wellbores, etc.). When flowrates become large enough, an instability appears where the liquid intermittently restricts gas flow, leading to the buildup of intermediate high pressure gas pockets that are eventually flushed as a slug until the pressure drops to a point where gas stops flowing again. This type of behavior is well attested on offshore risers and horizontal wells.

In this specific instance, Figure 2 displays 5 days of recorded stroke-by-stroke pump fillage. As one can see, the pump displays complex, but periodic, patterns over a of period of roughly 12 hours. While pump fillage averages 76%, it is in fact swinging wildly, peaking at 100% and falling as low as 40%. In particular, half of all strokes show fillage lower than 80%, a typical operational rule of thumb to avoid damaging the equipment.

Thanks to this detailed information, we are able to set up a controller that learns the dynamical pattern of the slug to stabilize it. The result of this process is detailed on Figure 3. After a learning period of 7 days, the slug is gradually stabilized, leading to a new flow pattern where pump fillage averages 90% and never goes below 80%, thus considerably reducing pounding and damage to the rod string. Additionally, the new control regime resulted in a 30% reduction of pumping unit runtime while also maintaining constant production (tested at 43 Boe/d before, and 45 Boe/d after the intervention), leading to an additional increase in meantime between failures as well as corresponding electricity savings.

CASE STUDY 2: INVENTORY TRACKING, SENSOR FUSION AND SMART ALLOCATION

Another key input in the production engineer's workflow is tank inventory data. Unfortunately, on oil tanks it often comes in the way of sporadic sensor readings, or worse, as manual gaging sheets. Additionally, water inventory is often not always tracked, as is typically the case on water flood fields. This is especially detrimental to the understanding of the field in formations where water makes up the bulk of the produced fluid. Furthermore, somewhat surprisingly, very few well controllers take advantage of this production data to increase their efficacy (*e.g.* by computing accurate pump slippage figures) or provide additional services such as out-of-the-box such as tank overflow alerts or mitigation (which is typically ensured by additional automation systems).

Acoustic Wells' system, on the other hand, was built from the group up as a fieldwide solution, providing high resolution monitoring of wells and tanks, both oil and water (along with other pieces of equipment such as compressors or salt water injectors, etc.). Figure 4 presents an example of the kind of high-resolution data recorded on a simple tank battery consisting of a stock tank and a salt water tank. While the oil tank data is fairly straightforward, the salt water tank level is difficult to process for a human due to the high fill rate and the transfer pump frequently kicking in to empty the unit. However, a machine learning algorithm can still process this data to extract useful production information. Figure 5 gives a sense of the granularity of the water flow rate data that can be obtained from such readings. Interestingly, this well exhibits a significant amount of structured variation in volumes of water produced, which is of interest to a reservoir engineering team.

This native integration of tank monitoring with well control presents many straightforward automation benefits. For instead, it becomes extremely simple to configure alarms shutting down production in case of tank overflow (or potential overflow), thus avoiding large remediation costs and environmental violations. This can happen either in the case where a transfer pump fails and is unable to empty a tank, or if a water leg is obstructed and leads to large amounts of produced water flowing to an oil tank.

Fusing this high-resolution tank and wellhead data allows for far more potent applications still. Figure 6 presents an example where such a monitoring system detected a collapse in oil production while water production increases, leading the operator to diagnose a casing leak. More generally, by fusing tubing pressure data, inferred well production estimated from dynacards and tank level data, one can readily detect surface leaks in real-time (for instance due to damaged flowline).

Ultimately, one of the key goals here is to integrate all these data streams to create a virtual flowmeter, allocating the production of a lease to various wells in real time, even when several producers are connected to one tank battery. Here we present the result of this analysis on a lease of three stripper wells. Figure 8 shows how the production history of the lease can be very accurately reconstructed using runtime (see Figure 7) and pump fillage data, allowing us to build a machine learning model providing real-time oil production estimates for each well. The results of this analysis are presented on Figure 9. Importantly, on this example we discovered that, unbeknownst to the operator, one of the wells was virtually producing no oil due to a very high water cut. This information was then used to prompt further investigation and prioritize capital allocation to optimize the economics of the field in given the context of high rig demand environment.

CONCLUSION

In this paper, we presented important advances in the field of long-range cellular telecoms and cloud computing that foster transformational shifts in oilfield automation. The novel approach developed by Acoustic Wells leads to (1) a collapse of hardware and installation costs, allowing for a wider adoption of those systems, (2) natively networked devices that seamlessly leverage each other's readings to monitor entire fields rather than any given asset and (3) high resolution data collection that provides unparalleled operational insights and novel optimization opportunities to increase production and equipment life-time while reducing power consumption.

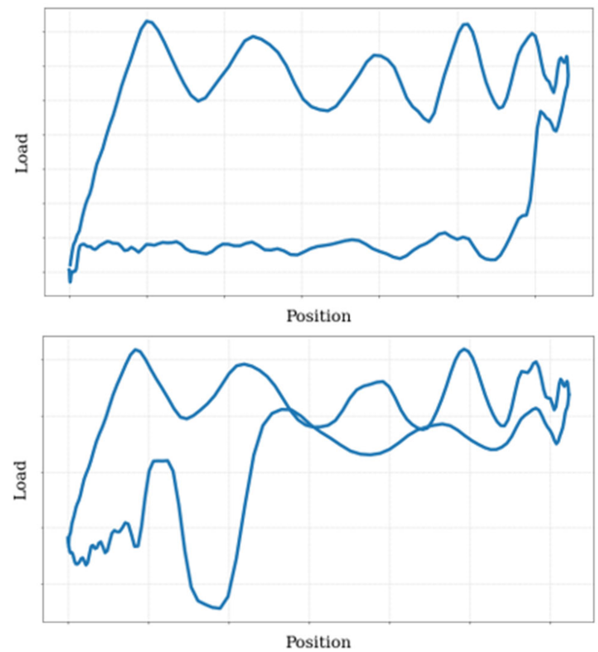

Figure 1 – Empty and full dynacards on a slugging well

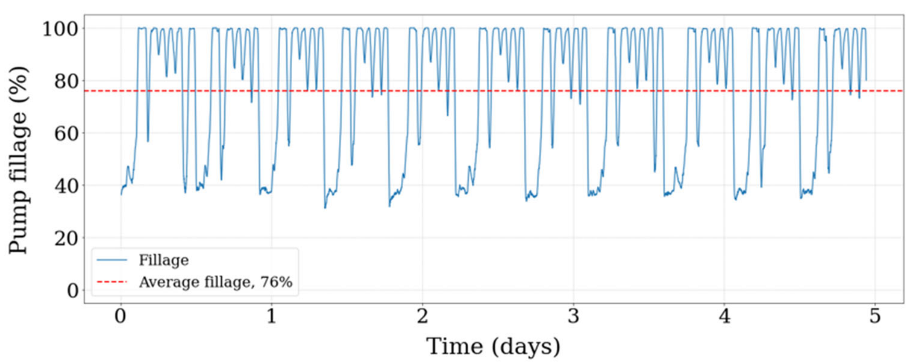

Figure 2 – Pump fillage pattern over 5 days on a slugging well

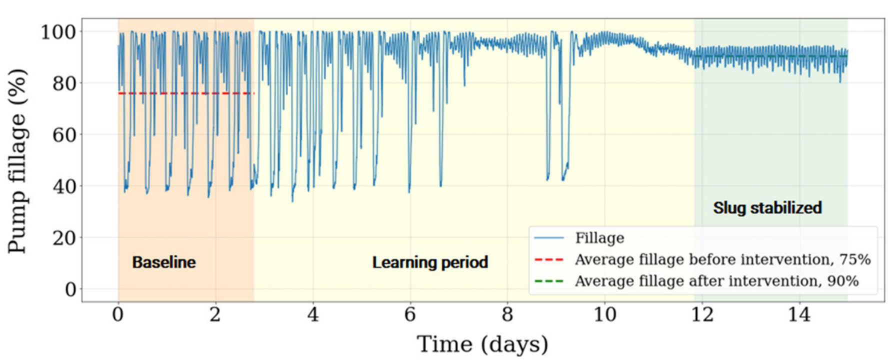

Figure 3 – Stabilization of the slugg by controller

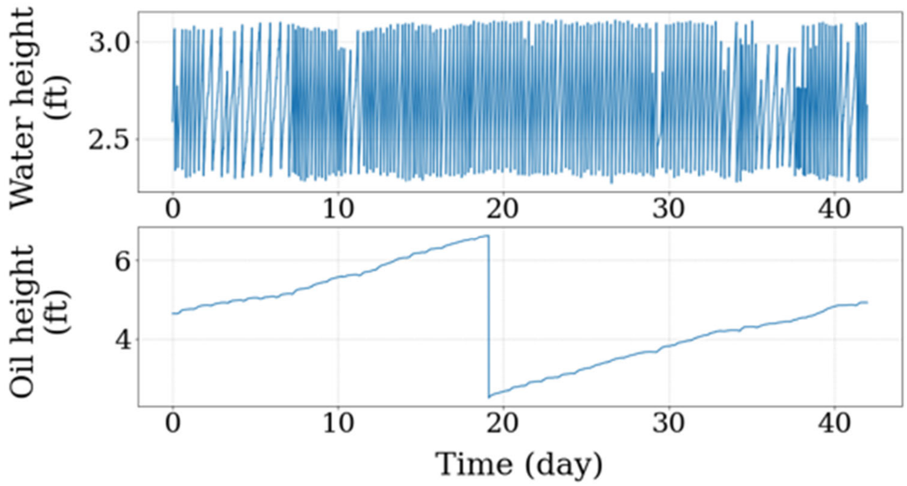

Figure 4 – Salt water and oil tank levels

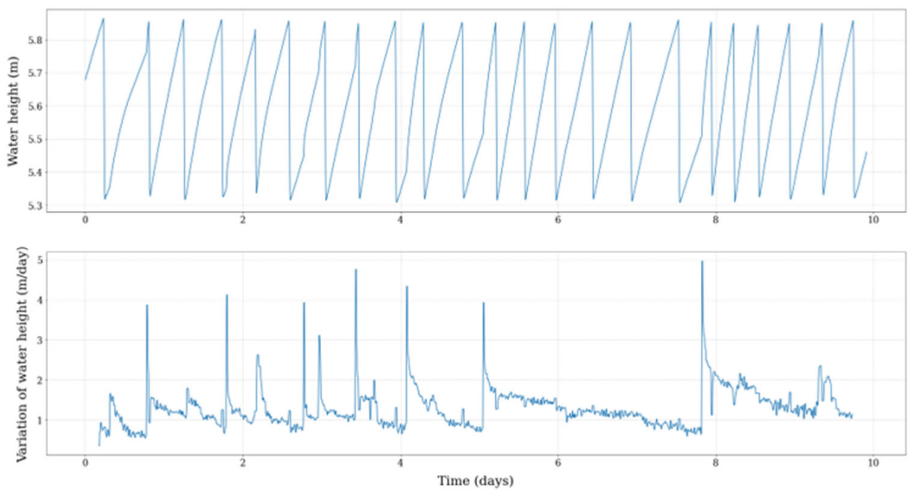

Figure 5 – High resolution water tank fillage data

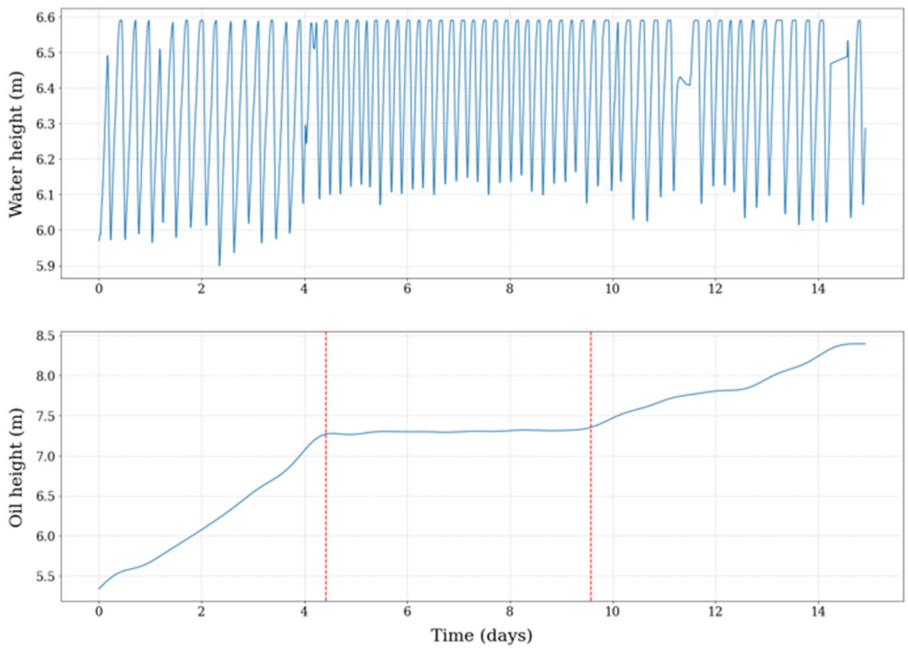

Figure 6 – Tank level data signaling a casing leak

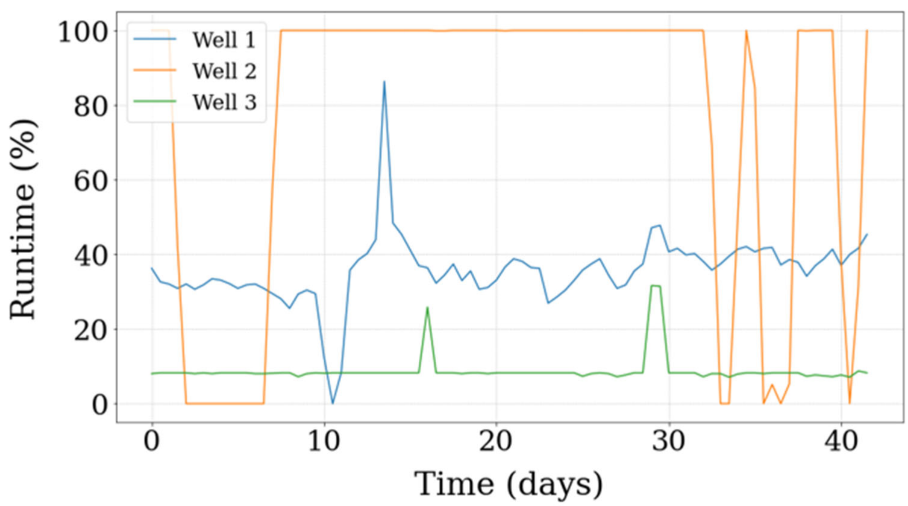

Figure 7 – Wells runtime data

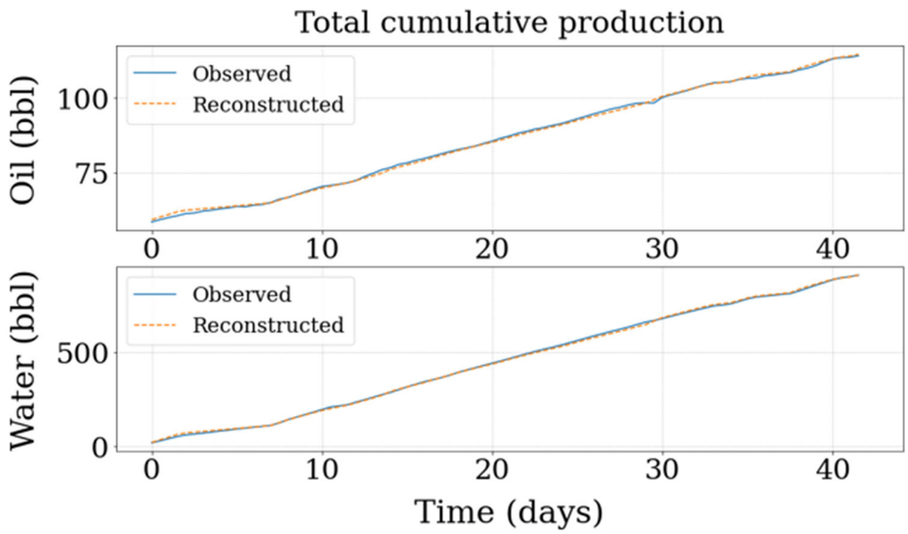

Figure 8 – Lease production reconstruction

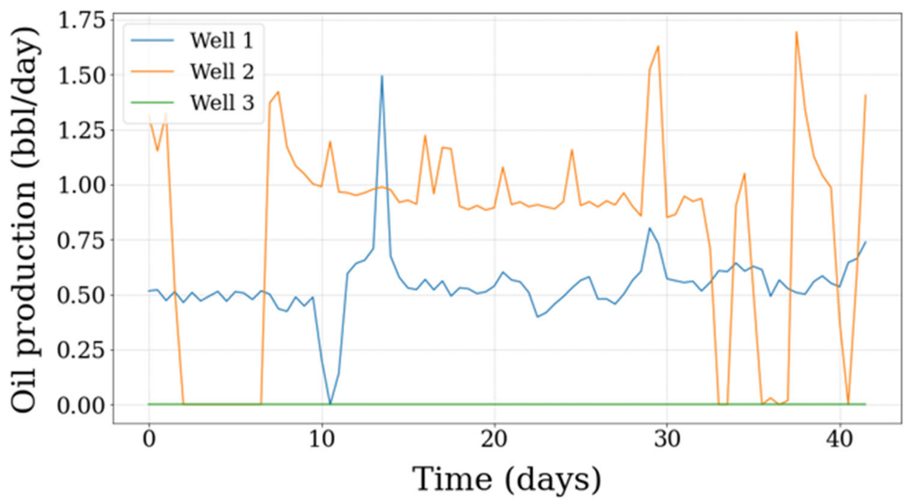

Figure 9 – Wells estimated flowrates