FY14 AOP 3.3.0.6 SURGE
Geothermal Drilling and Completions: Petroleum Practices Technology Transfer

Final Report

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Summary

In the summer of 2013, the NREL and CSM determined that an opportunity existed to improve geothermal drilling operations through transfer of practices from the petroleum drilling field. It was noted that significant changes in drilling efficiencies in petroleum operations had been made within the last decade. For example, five years ago 14,000 foot wells in Wyoming took 60 days to drill. In September of 2014, these same wells were drilled in 9 days. This improvement is the result of analysis, goal setting, and management and technology improvements. The geothermal drilling industry can import these methods and technologies where suitable and possibly see similar improvements in drilling operations.

The first step in this process is to identify the issues contributing to differences in petroleum and geothermal drilling performance.. Since time is a significant independent variable in this improvement, CSM set up a team of eager undergraduate students to analyze rig time data. The data came from IADC and Daily Drilling Reports. While IADC reports provide only a coarse time record, it gives a first approximation of where savings might be.

This report contains the analysis of 42 wells. Of these, 21 were geothermal drilling operations and 21 were petroleum drilling operations. For each well, the daily operations were inputted into a software database called IDS Datanet. This software is a web delivered online database that formats International Association of Drilling Contractors (IADC) coded daily drilling reports and then uses this daily information to generate time analysis figures.

The goal was to compare actual drilling performance to a theoretical "perfect well". That is, if everything went perfectly and all operations were optimized to the fullest extent (especially drilling penetration), what would such a well look like? This can be challenging to do without intimate knowledge of local drilling operations, so the team looked at this process in a "historical perfect well". The team looked in aggregate at all of the wells, and then looked at the best in class of the 21 petroleum wells and compared that to the best in class geothermal well. The results were astonishing.

Six major issues commonly found in geothermal drilling operations have been identified and compared to similar situations in petroleum drilling operations. These problems include lost circulation, rig and equipment selection, cementing, rate-of-penetration (ROP), efficient and consistent drilling program and effective time management. Due to these problems, as a whole, geothermal drilling operations analyzed in this report averaged 56.4 days longer than comparable petroleum wells. The petroleum wells reached an average depth of 12,500 feet faster than any geothermal well which have reached depths less than 10,000 ft.

There were many instances where comparable events such as drilling the same sized hole, tripping in/out, cementing, and running the same size casing took substantially less time in the petroleum operations. These comparisons are identified in the report and help show potential improvements of the geothermal drilling operations.

Lost circulation is the event in which the drilling fluid is lost to natural fractures and the pore space inherently present in formations underground. Losing this fluid to the formation will instigate a loss of pressure which can lead to intrusion of the natural fluids found in the rock (brine or oil and gas). This creates not only a safety problem, but is also economically detrimental. This is one of the major problems encountered while geothermal drilling.

Rig and equipment selection was another issue in the geothermal industry. Different types of rigs and drill bits are used in both the petroleum and geothermal sector. However, using the correct equipment and rig for the job creates huge opportunities. This was an issue found while completing the geothermal analysis for this report.

The next prominent issue plaguing geothermal drilling is the effectiveness of cementing the well after it has been drilled. Petroleum and geothermal wells are drilled, and then steel casing is inserted into the hole to prevent ground water contamination, produced fluid leaks and bore-hole stabilization. The casing must then be cemented in place. Cement however, is a heavy fluid. This density makes getting a full column of cement, necessary to combat casing failure, difficult to achieve in light of the aforementioned lost circulation issues.

Another issue highlighted during this research was low rates of penetration (ROP) while drilling. This is a broad obstacle because of the many factors that can aid or hinder ROP. Some of these influences will be assessed by this report, and include bit type, weight on bit, mechanical specific energy and others.

The fifth major issue affecting geothermal drilling is an efficient and consistent drilling program. In the petroleum sector, a drilling program is developed to manage rig operations. With the data available for analysis in this project, it would appear the geothermal industry could benefit from this crucial management tool

The final problem to be detailed in this report is the effective management of time by the rig and crew. This is difficult to analyze because of the disappearance of “lost time” within the reports. However it is one of the goals of this project to quantify the effect of inefficient time management seen in the geothermal field. This was not classified very well due to time step limitations.

Using these six problems to guide this projects research, data input, and analysis, a quantification of the time lost was identified, classified, and determined.

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Introduction

The National Renewable Energy Laboratory (NREL) has been funded by the U.S. Department of Energy Geothermal Technology Office (GTO) to identify petroleum drilling and completion practices (methods and technologies) that can be transferred to geothermal drilling and completion, to provide the geothermal industry with more effective, lower cost and lower risk methods.

The geothermal and petroleum industries share similar drilling and completion challenges, yet the petroleum industry has a large advantage in the scale of investment, people, and wells. This project's goal is to identify petroleum drilling and completion practices (methods and technologies) that can be transferred to geothermal drilling and completion and to provide the geothermal industry with more effective, lower cost and lower risk methods. This project to identify technology transfer opportunities began in FY14 and is continuing in FY15. The project has and continues to identify pathways for technology transfer and will advise Geothermal Technologies Office (GTO) on opportunities to accelerate technology transfer and testing of petroleum best practices for geothermal. The project will also identify opportunities for technology transfer from geothermal to the petroleum sector as appropriate.

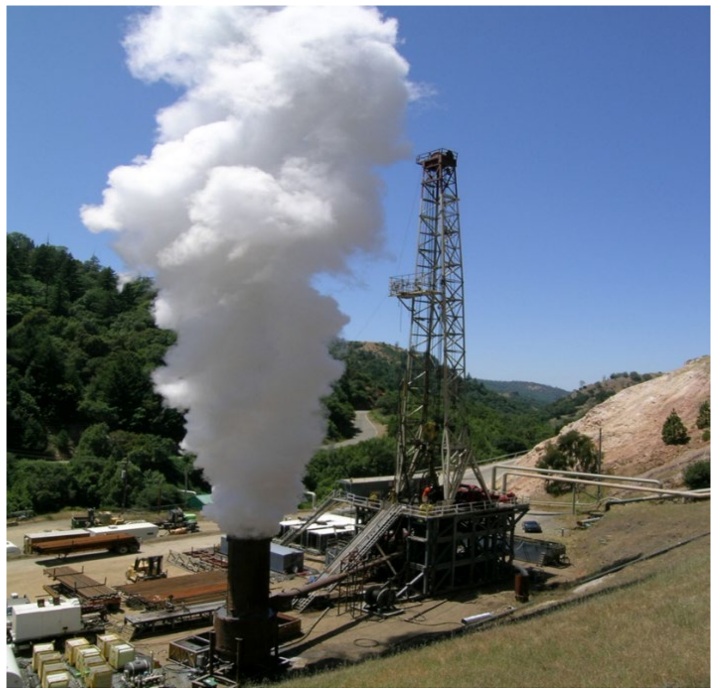

Figure 1: Geothermal Rig Site

This project supports the Geothermal Technologies Office's overarching goal of reducing drilling costs by identifying game changing technologies and methods, and will contribute to GTO's strategic target to reduce drilling costs by 30%. Geothermal drilling and completion costs are a large fraction of LCOE, and this project could potentially deliver 1-2 cents per kWh reduction in LCOE. Reducing cost and increasing drilling and completion success rates will make more geothermal prospects viable and enable faster capacity expansion in the U.S. The project will allow explorationists, drillers, and drilling and completion engineers in the geothermal industry to leverage the greater level of investment and experimentation that has taken place in the petroleum drilling and completion sector.

Background

This project will identify pathways for technology transfer and the Partner University will advise GTO on opportunities to accelerate technology transfer and testing of petroleum best practices for geothermal. NREL will lead the effort and the Partner University shall provide support.

The Partner University has provided the following:

1) Together with NREL, seek the input of geothermal industry experts and review the literature to prioritize the top several problems affecting overall well construction costs.

2) Conduct "perfect well analysis" on a set of real geothermal well construction records to define the physical limits to drilling and completion performance, to set performance targets, and to identify where petroleum technologies can yield the most significant performance increases and cost savings.

3) Correlate the findings from previous steps to confirm the key factors contributing to high geothermal drilling and completion costs.

4) Conduct analysis that accounts for correlation among variables, on the subcategories of drilling and completion activities (bits, casing, cementing, completions, verticality, lost circulation, process engineering, logistics, rig selection, etc.) to select the areas where improvements will have the greatest cost leverage.

5) Gather the input of petroleum industry experts to identify approaches to cost reduction in the key areas that have applicability to geothermal wells. CSM shall use its extensive contacts in the petroleum industry, as well as CSM/petroleum research consortia when advantageous.

6) Conduct targeted research of opportunities to transfer petroleum technology to geothermal, leveraging CSM engineering students to perform detailed investigations of specific technologies under the guidance of CSM faculty.

7) Because the support is collaborative in nature, no specific deliverable from CSM is expected; however, CSM shall contribute to the final project report to GTO.

A team of experts from CSM professors, including from the Unconventional Natural Gas and Oil Institute, and NREL geothermal staff conducted the project with a large amount of the research conducted by CSM undergraduate students. To quickly focus the team on the most promising areas of technology transfer, the team accomplished the following:

1) Solicited the input of geothermal drilling experts and companies to prioritize the top several problems affecting overall well construction costs as identified in the FY 14. The team also solicited active participation of experts at Sandia National Laboratory and the Department of Energy's National Energy Technology Laboratory (Houston). Potential opportunities to solicit feedback at various geothermal programs such as at this year's GRC are anticipated.

2) Collected drilling data from various sources, input that data into an industry standard database, analyzed the data for trends, anomalies, and general time use, and collected the results.

3) Conducted targeted research of opportunities to transfer petroleum technology to geothermal. This analysis included estimates of potential cost reduction that could be achieved in

geothermal applications if the technology transfer is successful, and the specific technical barriers that need to be addressed.

4) Documented findings and recommendations for technology transfer, technology development, and demonstration in geothermal wells. Provided recommendations for high-impact field demonstrations of drilling technologies. Reviewed Geothermal drilling operations in detail to determine issues related to rig operations, equipment limits, and data access.

The team over the last year has collected, input, and analyzed various well data (i.e. well daily drilling reports, bit and drilling fluid records, IADC reports) as part of a "perfect well analysis" on a set of real geothermal well construction records to define the physical limits to drilling and completion performance, to set performance targets, and to identify where petroleum technologies can yield the most significant performance increases and cost savings. To date, the CSM team has analyzed multiple records from various wells drilled under support of the DOE and a major geothermal operator. The team has also analyzed similar records from two petroleum operators. These have yielded what are called in drilling Key Performance Indicators. Comparing and contrasting the KPI's between Geothermal and Petroleum drilling operations will show where either group leads or lags the other.

Candidate geothermal wells for "perfect well analysis" were drawn from DOE funded field projects within the HRC and EGS programs (respecting all DOE nondisclosure requirements) in addition to well data from cooperative private sector companies (and respecting their nondisclosure requirements). The team was given record access to multiple DOE funded field projects. The team also had access to a major geothermal company records. With respect to the petroleum sector, the team was given access to two independent company records (with size comparable to the larger geothermal drilling operations)

Figure 2: Petroleum Rig Operations (Pad Drilling in the Rockies)

The project team included six CSM undergraduate students who, collected data from both industries, working primarily over the summer. The team consisted of five seniors (four from the US and one from Malaysia) and one junior (US), all petroleum engineering majors.

The student team enabled many inputs from both industries and leveraged the team's enthusiasm and creative capacity to spot patterns and technology transfer leads and projects. The project has developed a cadre of students with expertise in applying both petroleum and geothermal practices to solve geothermal drilling and completion problems.

Review of Experts in Geothermal and Petroleum Operations

In 2013-14 the co-PIs of this project interviewed leading experts in geothermal and petroleum drilling to identify the primary drilling and completion challenges faced by the geothermal industry and the state of the art in petroleum drilling technologies and practices. The results were illuminating and are shown in the data analysis from the team.

The Interview Process

The Co-PI's used a script for each interview to allow consistency in responses. That said, generally the discussions started on script and then veered as interesting points were brought up. The script looked like this:

1) NREL/CSM/DOE project objectives and timeline
   a) Note phenomenal petroleum drilling and completion improvements in last decade
   b) Link drilling operations and technology from petroleum to geothermal and back
   c) Identify and incorporate latest petroleum technology and operational management to improve economics of geothermal wells
2) Share our backgrounds
   a) Charles Visser
   b) Alfred (Bill) Eustes
3) Project approach
   a) Confirm greatest geothermal well construction challenges encountered by geothermal experts.
   b) "Perfect well" (Technical Limit, Drilling the Limit, etc.) analysis of a set of geothermal well construction records to identify most significant departures from "ideal".
   c) Correlate challenges (a) with departures from "ideal" well construction (b).
   d) Rank opportunities for exploration
   e) Explore petroleum practices, tools, and techniques that could address challenges.
   f) Identify opportunities for technology transfer of petroleum practices to geothermal well construction.
   g) Share with geothermal community
4) Greatest challenges in geothermal drilling
   a) Open inquiry: what are the greatest geothermal drilling challenges?
   b) "Greatest" defined as:
   c) Cost
   d) Impact on success/failure
5) If warranted, make the distinction between challenges driven by geologic uncertainty (exploration); vs. challenges driven by geothermal drilling conditions, practices, tools, completion requirements (development.)
6) Prompt them to discuss the range of well construction activities:
   a) Effectiveness of various drilling systems in geothermal environments
   b) Making hole
      i) ROP

ii) Critical path is "though the rotary table" efficiency
iii) Real time optimization
c) Acquiring geologic information
i) Logging while drilling
ii) Coring
d) Trouble avoidance and mitigation
i) Lost circulation
ii) Well control
iii) Rig issues
e) Casing design
f) Materials
g) Zonal isolation
i) Cementing
ii) Packers
7) Completions
a) Stimulations
8) Geothermal-scale production rates
9) Well longevity, geothermal system sustainability
10) Any specific suggestions for potential technology transfer?
11) Thanks and promised follow-up

Findings from Interviews of Geothermal Drilling Experts

The co-PI's identified various potential interview candidates in the geothermal drilling sector, emailed them for permission to call, and then followed up with those that agreed with a ½ hour teleconference. The geothermal experts identified and agreed to a teleconference are as follows:

Stephen Pye, Consulting Drilling Engineer.

- Unocal Research Drilling and Stimulation, Geothermal Group; Unocal Philippines; Philippine Geothermal, Inc., Mighty River Power; Geothermal Resource Group
- Four years as drilling engineer at the Geysers Field
- Geothermal drilling experience in the Imperial Valley/Salton Sea, Dixie Valley NV, Latin America, Philippines, Chile.

Bill Rickard, Geothermal Resource Group

- Unocal Geysers, Geysers Field Drilling Supervisor (14 years), Ormat
- Drilled geothermal wells in western US, Alaska, Hawaii (Puna), Southeast Asia, New Zealand, Africa, Turkey

Virgil Welch, Petroleum and Geothermal Drilling Consultant

- 43 years in the drilling industry, 75% geothermal
- Senior VP Gradient Resources (drilling/cementing company, built 14 drill rigs)
- Fenton Hill, Jemez Pueblo, Belize oil well

Paul Brophy, President and Principal Geologist, EGS, Inc.

- 35 years experience in geology and resource assessment
- Dames and Moore, California Energy Company
- Geothermal experience in California, Caribbean, International

Paul Graham, Drilling Engineer, Calpine

- Petroleum drilling (deep Gulf of Mexico)
- Geysers Field geothermal drilling

Louis Capuano, Jr., CEO Capuano Engineering Company

- 40 years in the geothermal industry (drilled 300-400 wells)
- Aminoil, Thermagenics, ThermaSource (founder/CEO of full service geothermal drilling provider)
- Worldwide geothermal experience in vapor dominated fields, liquid dominated fields, geopressure geothermal reservoirs, and EGS geothermal systems.
- Geothermal Resources Council Board of Directors, former GRC President

Douglas Blankenship, Manager, Geothermal Research, Sandia National Laboratories

- 30 years' experience at Sandia and the private sector in the development, testing, and monitoring of drilled and mined openings in subterranean environments.
- Research in drilling technologies to reduce drilling cost and risk in harsh, environments, including high temperature electronics, advanced bit development, geothermal energy & drilling technology, advanced systems & diagnostics while drilling, computational modeling, wellbore stability

The co-PIs took extensive notes and have condensed and consolidated the findings from the many interviews. Please note that the following is a summary of the common themes heard and cannot be attributed to any individual based on the co-PI's paraphrasing. What the co-PIs were able to do was to find eleven themes. These are listed here:

Small Community

There is a very small community of highly experienced geothermal drilling experts in comparison with the petroleum industry, reflecting the far greater number (three to four orders of magnitude) of petroleum wells drilled versus geothermal wells. Our interviews of seven geothermal drilling experts tapped an extraordinary concentration of experience, with most having experience with scores or hundreds of geothermal wells over decades long careers. The small community of long career geothermal drillers provided valuable perspectives on the evolution of geothermal drilling over the past several decades. Unfortunately the pipeline of young geothermal drilling engineers is sparse, given the dominance of the petroleum drilling career paths.

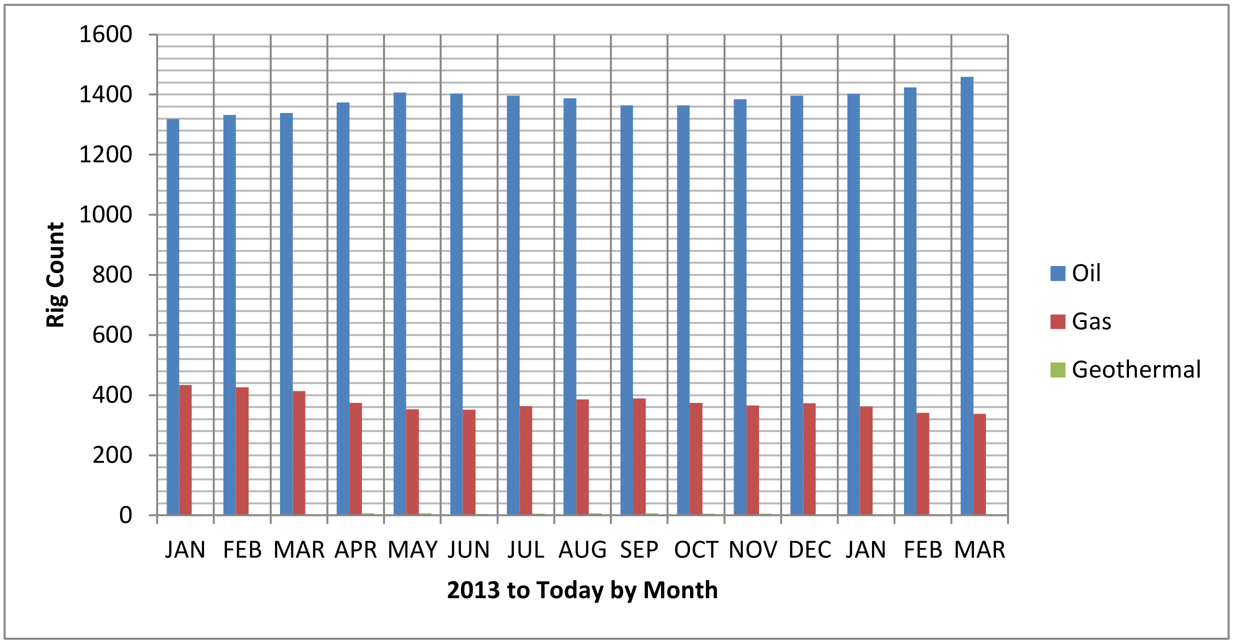

Figure 3: Rig Count of Oil, Gas, and Geothermal Drilling as of March 2014

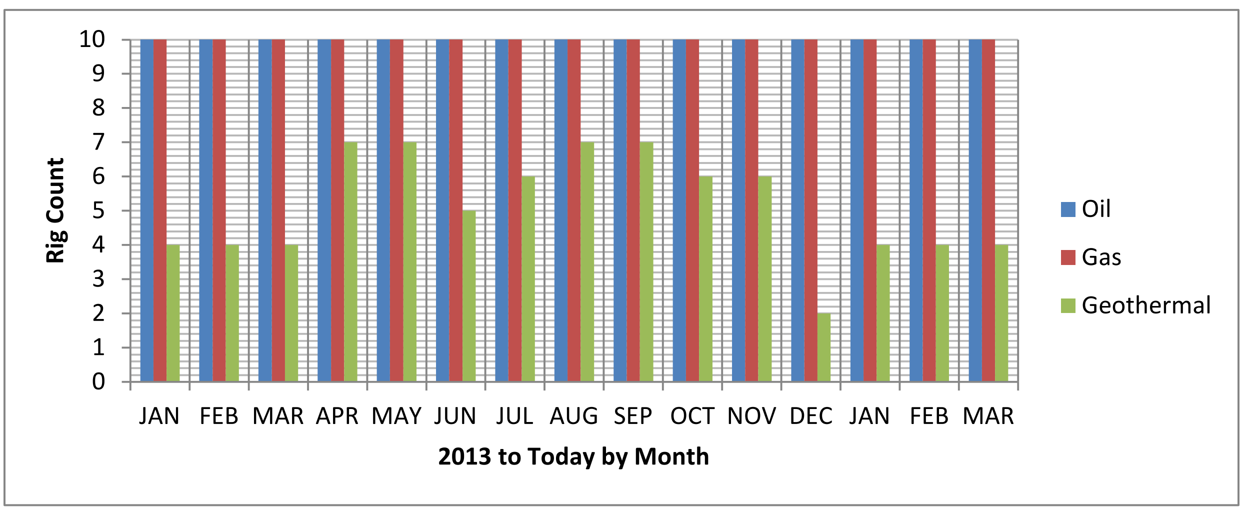

Figure 4: Close up of Figure 1 showing Geothermal Drilling Wells

The One-Off Nature of Most Geothermal Wells

Dialog with these experts reinforced the idiosyncratic nature of geothermal wells due to the geologic complexity of the habitat of geothermal resources, poor geologic mappability, secondary mineralization, fracture dominated permeability, and poor correlation of geothermal rocks using electric logs. "Even geothermal development wells are relatively blind," said one expert.

Severe Physical and Chemical Conditions

High to severe temperature in the geothermal environment is a crosscutting challenge that impacts every other geothermal drilling and completion challenge. Geothermal drillers must manage the risks of blowout and boil out. Corrosive fluids and precipitation (scaling) are common problems related to high temperature geothermal fluids. The presence or risk of H_2S precludes higher grade drill pipe that is subject to sulfide stress cracking, requiring heavier pipe and heavier drilling strings. One expert compared geothermal drilling conditions to 20,000 foot petroleum wells and noted that some geothermal environments have far more extreme conditions.

Drilling Operations: Departures from Perfection

The geothermal drilling experts recited many examples of drilling challenges including low rates of penetration (ROP), excessive wear, lost circulation and other problems detailed below. Tri-cone bits typically have a short life and low reliability in the geothermal drilling environment. The use of PDC bits has increased ROP in some geothermal rocks; but, PDC bits are not always effective, especially in inconsistent rock conditions of hydrothermal and clay alteration. The additional cost of PDC bits can be difficult to justify with the high uncertainty of geothermal drilling conditions. The heat also affects the longevity of "rope, soap, and dope", the expendables of any drilling operation.

High Wear

High bit wear is a common challenge in geothermal environments with high temperatures and high abrasion from drilling with air/aerated systems. "Air drilling at the Geysers, we cannot run a brand new bit more than 24 hours," said one expert. Wear is a major problem for many other components of the geothermal drilling operation, including pump parts, shaker screens, drill pipe (requiring expensive tungsten hardbands), drill collars. "The cost of expendables on geothermal wells is four times that of a petroleum well," said one expert. The same expert estimated that drill collar and drill pipe life in geothermal wells is a fifth of petroleum wells.

Figure 5: Drilling is Tough on Bits

Lost Circulation

Lost circulation is viewed by many of the experts as *the most expensive* problem in geothermal drilling. In addition to the challenges posed by lost circulation in making hole, cementing, and other operations, getting stuck is a very common problem in geothermal wells (33-50% probability in one expert's judgment.) One expert measured his progress in managing lost circulation by the declining number of cement plugs he has set in drilling geothermal wells over the years.

Directional Drilling Challenges

The heat limitations of directional drilling tools are a major challenge. Geothermal exploration and development clearly could benefit from horizontal drilling to better intersect subvertical fractures but high temperature electronics and MWD systems are required.

Geologic Challenges

Geothermal exploration usually involves lower confidence levels than petroleum exploration. Geothermal exploration is fairly successful at defining the *environment* that could host a geothermal system but well site selection is challenging because prediction of lithologies and fracture permeability is difficult. Geophysical logs have limited resolution in typical geothermal lithologies and often putting logging tools in the wells is risky. Many geothermal wells have little or no logging program as a result. Fracture identification by logs is challenging. "Often we complete a well, go back, clean it out, and find that the fracture zones are a lot different than we thought when we were drilling," said one expert.

Figure 6: Geothermal Drilling Rig

Cementing

Cementing challenges include frequent lost circulation in geothermal rock environments, lack of returns and low returns, low fracture gradients, difficulty in detection of cement bond, large casing sizes, micro-annulus issues, and high temperatures requiring cooling to enable successful cement jobs. Standard cements are unsuited for high temperature environments and alternatives are few and expensive. Geothermal cements must endure expansion and contraction, and such cements make logging the cement bond difficult.

Casing Design

Failed casing couplings are a common problem under the severe conditions of heat and stress, requiring the use of more costly casing connections. The poor predictability of geothermal geology makes flexibility a key aspect of well design. "Sticking to the casing plan is difficult", said one expert.

Drilling on the Cheap

Few geothermal exploration and development companies have the resources and opportunities to drill large numbers of wells. Funding is difficult to come by and investments in new approaches and speculative data collection are less common than in the petroleum industry. A common challenge cited by experts was the tendency for geothermal wells to be drilled "on the cheap," a reflection of the economics of geothermal relative to petroleum, the high risks of geothermal drilling, and the high geologic uncertainty. The "one off" nature of geothermal wells, combined with high cost sensitivity, are barriers to effective learning in the exploration and development process, which is a barrier to risk reduction.

Findings from Interviews of Petroleum Drilling Experts

The co-PI's identified various potential interview candidates in the petroleum sector, emailed them for permission to call, and then followed up with those that agreed with a ½ hour teleconference or personal interviews. We focused on those with operations that the petroleum experts identified and agreed to a teleconference or interviews are as follows:

Chuck Mallory, Director of Drilling Technology Rocky Mountains, Noble Energy Company

Tommy Thompson, Director- Engineering and Technology, Anadarko Petroleum Corporation

Nick Spence, Drilling Engineering Manager, Anadarko Petroleum Corporation

Robert Sencenbaugh, Drilling Engineering Manager, Sklar Exploration Company

Roy Long, Ultra-Deepwater Technology Manager, National Energy Technology Laboratory Houston

Figure 7: Wyoming Petroleum Well

The co-PIs took extensive notes and have condensed and consolidated the findings from the many interviews. Please note that the following is a summary of the common themes heard and cannot be attributed to any individual based on the co-PI's paraphrasing. The co-PIs found five themes:

Limited Economies of Scale In Supply

The co-PIs expected that the huge difference in the scale of the two industries would give the petroleum industry a cost advantage through volume purchase of supplies.. One drilling expert questioned the advantage, saying that any advantage from volume was offset by the requirements of reliable and ready availability and high quality customer service. With the "factory" drilling mode these companies do requires the close cooperation between the operators, contractors, and suppliers.

Rig Technology (Built for Design)

Figure 8: Sensor Output on Modern Petroleum Rig

One of the largest drivers for the improvement seen in petroleum drilling operations is the "built for design" drilling rigs. Today's latest drilling rigs are continuing to be mechanized and automated for not only drilling operations but also the other support operations that are required to mobilize, run, and demobilize drilling. The rigs today have variable frequency drives that allow for the fine tuning of operational parameters, extensive sensors for monitoring drilling operational parameters onsite and remotely. This also allows for the capture of drilling data for analysis after operations cease for improvements. The rigs also have top drive rotary systems for continuous circulation, even while tripping if needed. Many have been mechanized including "iron roughnecks" that take the human out of the movement on the rig floor for safer operations. The driller now sits in a comfortable cabin in a chair with virtual instruments, video systems, and communications at their fingertips. While these rigs command a higher day rate, they are able to accomplish many drilling tasks efficiently and take far shorter times than their older, less capable predecessors.

Hardware Improvements

Figure 9: Modern Land Rig Operations Center

Hardware improvements are in a state of continuous flux. For example, given that today's Polycrystalline Diamond Compact bits (PDC) are molded and manufactured to suit, they are far easier to tweak and optimize for a given geology than tri-cone bits, which have a fixed manufacturing process. Of course, there is a cost for such versatility, but the bit can be optimized more quickly and lasts much longer (assuming proper running and drilling operations). Other improvements, include downhole real-time measurement, in-field referencing for better survey quality, and increased drilling fluid lubricity.

Automation

One petroleum drilling expert commented that drilling rig automation helps with safety but not with speed. This comment suggests that a significant opportunity remains for drilling performance improvement from automation. In comparison with airline operations, car manufacturing, and Coors beer can processing, there is still a lot room for growth in drilling rig automation.

Drilling team

The petroleum interviews indicated that the human capabilities of the drilling team are a key success factor. The drilling team must integrate the capabilities of the operator, service companies and contractors. The one critical driver of the phenomenal improvements in petroleum drilling performance is the drilling systems provide feedback to the drilling team which enables continuous improvement. Many small items contribute to more effective, lower cost drilling. Improvements are made by experimentation, learning what works, what doesn't work, and what may work next time. This not only includes drilling operations for wellbore construction; but includes logistics, preparation, materials, and especially procedures. The team noted that learning from experimentation in a series of similar wells is more challenging for the geothermal industry given the one-off nature of many wells

The high turnover of rig crews is a major challenge in petroleum drilling operations. One operator commented that the rate was "40% a year". Turnover inhibits team learning and performance. However, the turnover rate for operators was much lower. In addition, the operators did not try to 'spread their engineers thin". One operator had one drilling engineer focused on one or two rigs at most. This gave the engineer time to focus on continuous improvement.

Figure 10: Iron Roughneck, an Example of Rig Mechanization

The Perfect Well

What is the Perfect Well?

The petroleum industry has many analytical tools to pursue improvements in drilling operations. These go by various trademarked or patented names such as Technical Limit, Drilling Wells on Paper (DWOP), Drilling the Limit, Fast Drill, and the Perfect Well, to name a few. The goal is to effect a step change along with incremental change in drilling operations efficiencies. Nothing is "off the table" for analysis. As an example, a petroleum operator in Wyoming five years ago was drilling wells to 14,000 feet in 60 days. In September this year, the same operator went to the same depth of 14,000 feet from spud to TD in 9 days. They *averaged* over 1,500 feet per day penetration!

The Perfect Well is a concept patented by Dr. J.F. Brett of Oil and Gas Consultants, Inc. He graciously gave our team free permission to use this concept for the analysis. The Perfect Well is the absolute fastest time that a well could possibly be constructed– the theoretical physical limit of what can be done. This not only includes rate-of-penetration drilling operations; but, also the many other things that affect drilling operations. These are the so-called flat times, named for the lack of progress on a drilling time versus depth (DVD) chart frequently used to determine drilling operation tempo.

Firm drilling benchmarks are difficult to find. Well depths change, the drilling environment is different, hole sizes vary, casing setting depth varies from well to well, and sometimes you have lots of information and history in an area, other times you have very little. The Perfect Well concept provides an objective measure of well construction effectiveness. Wells that operate at twice the perfect well are overall more efficiently constructed then wells constructed at five times the perfect well.

The Discovery Enterprise class drill ship of the Transocean Drilling fleet was built to create this step change. The engineers analyzing the time spent in drilling offshore came to some pretty startling, yet obvious in hindsight, conclusions. When one considers the "critical path" in drilling operations, that path always goes through the rotary table. In other words, anything that slows down the wellbore construction process in the hole is slowing the entire operation. One such operation in offshore drilling is the running of the subsea blow out preventers on a riser. It was taking five days and at $1,000,000 per day, significant. So, the engineers built two rotary systems. The forward table was used for drilling operations in wellbore construction (the surface hole drilling in this case). The aft rotary system was used to run the BOP stack and riser. It was off the "critical path" and was not slowing anything down. Once the surface hole was cased and cemented, they moved the ship 40 feet forward and immediately connected the stack to the subsea wellhead and started the next section of hole. This saved five days of rig operations and the subsequent expense.

What are the limitations and measurement of well construction efficiency?

There are many issues at work in limiting the perfect well. These include:

NPT (Non-Productive Time)

This is time that is spent in not constructing the wellbore. This does not include operations such as running casing, cementing the casing, logging the well, and so forth. Those are all necessary to the construction process. However, anything that does not contribute to the construction of the wellbore would be NPT. This would include rig repairs, waiting on logistics, weather, etc. There are also other events, called "unscheduled events" which is a nice way of saying something has gone wrong. It can be driven by the rig and people or by Mother Nature. Examples include well control incidents, lost circulation, lost equipment, rig breakdown, etc.

ILT (Invisible Lost Time)

This is time lost due to inefficiencies in operations. An example would be running casing. What if one rig crew could run 4,000 feet of casing in four hours and another crew running identical casing to the identical depth takes six hours. The additional time may be due to mitigating factors such as weather or it could be that it just takes longer to run the casing for whatever reason. The two additional hours are ILT. Inefficient drilling could also be an issue. For example, if drilling dysfunctions such as drill string whirling, the bit or formation balling, or bit stick/slipping, each of these takes energy away from the penetration of rock which gives the ROP. That, too, would be considered ILT because if one could eliminate those dysfunctions, the maximum drill rate would be realized.

KPI (Key Performance Indicators)

The use of Key Performance Indicators allow for the analysis and comparison of operations and the associated equipment and personnel. Examples of KPI's are

- The time between well spud and rig release ("spud to rig release time").
- ROP for a given interval.
- NPT for a given well or it could be related to many wells or even field wide or companywide.
- The speed of delivery or the costs of wells or reliability rate of downhole tools.

A KPI must be measurable, easily understood, and comparable. KPIs are typically related to, but not limited to, financial and technical measures. They must relate to some desirable goal. And they must be able to generate an action to improve the KPI. Developing KPI's for the geothermal industry would be useful.

How can Perfect Well Analysis help?

The Perfect Well procedure can identify the aspects of geothermal well construction that depart most significantly from the Perfect Well and by comparing these departures with Petroleum drilling operations, gain an insight into drilling improvements. It is granted there are significant differences in the conditions encountered in geothermal and petroleum drilling. However, there are many similarities, too, and it is there that gains can be made. By comparing the perfect well to reality, goals can be set to start the process of achieving those perfect conditions. The truly perfect well will never be achieved. Knowing the difference between a perfect well and reality represents an opportunity and given the time and equipment, the economic value of pursuing perfection.

Calculating the Perfect Well

The perfect well can be determined by summing the absolute minimum time with the minimum number of steps necessary to construct a borehole. This implies a minimum number of casing strings, the minimum size borehole and pipe needed, the minimum time and the minimum number of steps to safely create a given borehole.

This calculation can be performed from the bottom up or the top down. In a bottom up approach, drilling engineers estimate every step needed to drill a section of borehole. Each step would have a metric associated with it and a “perfect time” in which to achieve it (based on experience, equipment capability, safety). ROP can be estimated with mechanical specific energy means (MSE). Top down would be to determine examples of other wells and intervals that were minimum (which is called “historical perfect well”), sum all those minimum up, and call that the perfect well. This may not be a perfect well by the definition above but it is real in the sense that “somebody” did achieve that time and effort.

In this project, the team used this approach to compare geothermal and petroleum operations. The ratio between the perfect well time and reality is a useful measure of the potential to make a step change. By analyzing step by step of the drilling process and comparing and developing a ratio, the areas ripe for improvement can be determined. It is a method for the determination of resource allocation to make ‘the perfect well”.

Analysis of the Drilling Data

Background

The team was able to access twenty-one geothermal well drilling data and twenty-one petroleum well drilling data. The data was primarily the daily drilling reports with time broken into 15 minute increments. These problems including lost circulation, rig/equipment selection, cementing, rate of penetration, presence of a drilling program, and time management of the rig and crew. By comparing geothermal drilling processes to those in the petroleum industry, these six problems can be compared and identified in this report.

This data was spotty, especially for some of the geothermal wells. This lack of drilling data, both from a timing aspect as well as basic engineering data such as bottom hole assemblies, bits, and drilling fluid properties, hampered the team's efforts to analyze the data. In contrast, the petroleum well data was well organized and, for the most part, complete. In addition, there was consistency between the petroleum drilling well data, even between different operators. There were six geothermal drilling operators of varying sizes involved in some of the wells with one dominant operator. Consistency of terminology and timing hobbled some of the work. The team did its best to interpret some of what was happening on a rig. Any discrepancies between what was in the records and what really happened can be attributed to this issue.

Since there were no electronic records of geothermal drilling operations, only IADC daily drilling report type records were analyzed. Electronic records commonly used in the petroleum industry include the various rig sensor data recorded every ten seconds (although every second is better and allows for automated analysis). This gives objective data that can be analyzed by footage or time. This data can be used to focus on many of the issues that can plague a drilling operation. By looking at the operational details, operators, contractors, and service companies can identify non-productive time and invisible lost time. And knowing when and where these happened, these groups can determine the root issues and causes and possibly do something about it. This process has enabled petroleum drilling efficiency to significantly improve in recent years.

Materials, Methods and Procedure

Four stages of activity were required to reach the final analysis. These stages included research, data gathering, data input, and data analysis. The first stage, research, consisted of gathering supplemental background information on geothermal drilling and the major problems associated with it. After a more in depth understanding of these issues in relation to the geothermal industry was acquired, the second stage involved collecting the hard data.

Forty two wells were acquired from three separate companies. Of these wells, 21 were geothermal wells and 21 were petroleum wells. The geothermal wells were drilled in the western United States. They were in typical geothermal provinces with igneous and metamorphic rocks. The petroleum wells that were analyzed were collected from petroleum plays in Louisiana, Colorado and Wyoming. These are all typical sedimentary petroleum reservoirs. We were successful in retrieving data from a major geothermal drilling operator and some from independent geothermal operators. We also were able to retrieve operations data from two petroleum independent operators.

The third stage involved analysis and entry of the data from all 42 wells. Specifically, the analysis process for the 21 geothermal wells was complicated. The wells were all inputted into a software database called IDS Datanet which will be covered extensively later in the report. This software was designed mainly for petroleum drilling operations. Therefore, it was difficult to assign codes for many of the geothermal operations. An few examples are air drilling and drilling with specific hole sizes. In the software, there is no code for air drilling which makes it difficult to show when the geothermal wells were drilled with air instead of normal drilling mud. Also, typically for petroleum wells, there are no 8 1/2" or 10 5/8" drill bit sizes, however, these sizes were common for the geothermal wells analyzed. Because these hole sizes are rare in petroleum wells, the IDS software did not include these hole sizes in the IADC codes. In order to assign these sizes to the correct code the generic "drill pilot hole" or "drill hole section" code was assigned. This made it difficult to sort some of the data.

The fourth stage, constituting the majority of this report, is the data analysis. In order to have a benchmark, the time analysis of each of the geothermal wells was directly compared to petroleum wells with similar characteristics. For example, when analyzing cementing time, a geothermal well will be compared to an petroleum well with the same casing and hole size or as close to the same as available from the data. For problems such as lost circulation that only occur during the geothermal operations, different approaches used within just the geothermal operations will be compared to show which method resulted in the fastest solution.

IDS Datanet software is a breakthrough effort by Independent Data Services. It has been around for the past 15 years [9] with primary uses being to be able to input working data for drilling and work over operations for any types of pay such as petroleum, geothermal, helium and water.

The software has been designed in a user-friendly format. At the beginning, it is arduous to figure out the right tabs to begin plotting the work. This is because the interface looks complicated with ambiguous tabs. However, it becomes very handy and easy once constant practice went on. To begin with, there are a total of 7 tabs in the software. These are available upon login. Below those tabs, there are drop down mini-menus, namely 'Well/Ops" and "Datum" in order to pick the well that is being worked on and the associated datum respectively. Below those small menus comes the main working space for the software. The next two paragraphs will explore this software by peeking into each tab and analyze its functionalities in detail.

The first tab is called "Main". The first function that is listed under this tab is the data population matrix data. Data population matrix reveals the entire platform and modules for an important tab "DrillNet", which will be discussed later in this write-up. Intersecting elements in this red-green matrix can be clicked in order to access detailed per-day activities of respective wells. The second function listed down under this 'Main" tab is the Operation Information Center Data. This is useful to show the summary well's operations and rig data. The following "Well Explorer" button pops up a spreadsheet like list that opens up on data regarding the operations, well names and its one liner daily information.

The second tab is called "Well Data". Well Data has three main functions under it, namely Well, Wellbore and Operation. New well names are added in the "Well' page by writing down the well name and the country and state information followed by indicating its location (offshore/onshore), pay type (geothermal/Petroleum /oil/helium/gas/water) and ground level in feet. After setting the GMT Offset value and writing down information on the location detail, it's time to move on the next function: Wellbore. This function can be used to name the well, its wellbore's name, purpose and type. Wellbore purposes include appraisal, delineation, development, exploration, injection, production and other. Wellbore type on the other hand includes pilot, initial, sidetrack, slot recovery, mechanical sidetrack and multi-lateral log. The next tab is the "Operation" tab which can be used to state the operation and completion type, mention the operating company, and operation rig. Apart from that, start and spud date & time could be selected from a list of drop down menu.

The third tab under concern is the "Rig Data". This tab can be used to take a look at the list of rigs and uses for the wells. Rig name, drilling company, owner, rig type and max depth can be overwritten. The tab used to output the data using figures is the DrillNet tab (light blue in color). The first function under this tab is called "Daily". This can be used to write the day, the number of the day, rig used and its manager, days spent on well, days since spud, current hole size, midnight depth, last casing size, and last casing shoe (MD/TVD) as part of the data as of report time. Furthermore, it can be used to write down the summaries and plans for that particular day which includes the status at midnight, 24 hour summary, status at 06:00 hours and the day plan. The next function under this tab which was used extensively in the data entry is known as "Activity". Composed of five rows (start time, end time, amount of hours spent between this interval, description of activity, codes and depth), the activity function is the deciding function to output vital results to be studied and analyze at the end part of this data tabulation work.

Most of the geothermal wells analyzed in this research project had daily drilling reports starting at its operation at 00.00 hours and ending it at the 24th hour. After selecting the respective day at the previous "Daily" tab, the next step was to enter this activity tab and start tabulating per day, per hour information for each of the operations in that particular well. After selecting the start and end time based on the daily drilling report, the software calculates the total hours spent between those two intervals. Next up is the description. In order to facilitate the work faster, more efficiently and smoother, it's important to read and understanding each activity and then tabulate it in the "description" text box. Following that, it's necessary to sort each activity with its respective IADC code. Under this column, there are three fill up boxes named Class, Phase and Operations. For this research purposes, only two out of the four operations provided were used; Programmed Event (P) and Trouble – During Program (TP). Phase describes the stage of the operation a well is having at that instantaneous point of time. The list of phases available are casing (with different diameters), diverter/wellhead/BOP, drill hole section (with various diameters), drive conductors (with various diameters), fishing /milling/cutting/perforating, formation evaluation coring, formation evaluate logging, liners (with different diameters), pilot hole, plug and abandon, plug back/cement plug, pre-spud operations, side track, suspension and well control. Next up is the operations type that varies according to the type of phase selected.

To provide an example giving a clearer picture on how this “Codes” part works, assume the type of class selected for an activity in the description is Programmed Event (P). Also assume the code is “Drill Hole Section” to represent a drilling activity during that period of time. Under that phase, the list of operation available for selection would be circulate to condition mud, cure losses, directional survey, download LWD, drill ahead rotary, drill ahead RSS, drill ahead sliding, drill off test/fingerprint, drill ahead hole opening/under reaming, FIT/LOT, FIT/LOT circulate condition mud, flow check, L/D BHA, L/D Retrievable Packer, M/U BHA, M/U MWD/LWD, Pre-Job Safety Meeting (PJSM), POOH in casing, POOH in Casing Back Reaming, POOH in Casing Pumping, POOH OH, POOH back reaming, POOH retrievable packer, POOH running tool, pump pill, repeat section log (RSL), rig maintenance, RIH in casing, RIH in OH, RIH retrievable packer, RIH running tool, RIH wash ream, RU to run directional survey, set and test retrievable packer, shallow test MWD/LWD, skid rig, slip/slip and cut block line, slow circulating rates, SPUD and drill ahead hole opening/under reaming, SPUD and drill ahead rotary, SPUD and drill ahead RSS, SPUD and drill ahead sliding, squeeze, wiper trip/check POOH back reaming, wiper trip/ check trip POOH pumping, wiper trip/ check trip RIH, wiper trip/ check trip RIH was ream and work/jar drill string to free stuck pipe. If the activity part stated that the particular operation faced a lost circulation problem, then the class would be changed from Programmed Event (P) to Trouble – During Program and an additional text box would appear with the name Root Cause (RC). Under this RC drop down list, possible selections representing the specific problem instigators would include lost circulation, stuck pipe and accident/injury, etc. This “Codes” part of the data tabulation is vital to produce meaningful and correct data at the end of the process. Sometimes, the job becomes easy with the report having activity acronyms that match the ones in the phases such as SUSP for suspension, SITR for side track, WECO for well control and FELO for formation evaluate logging. Otherwise, it takes time to identify the right activity in the phase.

Below the “Daily Activity” page, the number of days is listed. This makes the task easy when it comes to navigating across days of activity faster. The “copy/paste from yesterday” function found at the top of the page cut downs the time required to spend on tabulating activities into the software. It could help in copying activity details from the previous days and pasting it in the current day panel. The next important tab is the VisNet Basic. This is the hub for all the results storage based on the previously completed data tabulation. The most important sub-function under this tab is the double drilling dashboard. This can be used to display current well’s information and is particularly useful to compare data from multiple wells. Under this function, ten types of final result that lays out one or many well’s particulars in excruciatingly details can be obtained. The first is the planned vs actual plot, which is basically the drilling time curve. With depth in feet on the y-axis and days (d) at the x-axis, the wells performance and ROP can be evaluated over time. Due to lack of data, the borehole schematics weren’t used much, similar to the vertical section and plan view. The next vital piece of information is the root cause breakdown. It lists the types of troubles encountered during the drilling/work over operations in the well(s). An example of a root cause breakdown window (one that belongs to well Geo 12) is shown in Table 1.

Table 1: An Example of a Root Cause Breakdown Table

Root Cause Breakdown (Current)

Root Cause Code Breakdown

Root Cause Code	Total Duration (h)
Stuck Pipe (DSP)	8.50
WOT (Wait on tools)	10.50
WOR (Wait on repairs)	11.00
Labour industrial dispute (DLD)	16.00
Other rig contractor equipment, personnel or procedures (DRO)	26.00
WOC (Wait on cement)	26.50
Mechanical Borehole (DHC)	36.50
WLD (Wait on daylight)	43.00
Lost Circulation (DLC)	497.55
Total	675.55

As observed, the table lists down the troubles faced by a well and by using the details of information provided by the above table, one could identify the main problem which is hindering the drilling process of the well(s). Next up, phase codes breakdown displays the types of phases the well(s) went through throughout its operational time. An example of a phase code breakdown (one that belongs to well Geo 12) is shown in Figure 11.

The other two important final result charts are the drill down and class code breakdown charts, which are represented in Figure 12 and Figure 13.

As seen in these figures, the class code breakdown and drill down chart represent similar data presented in different formats. The orange part of the data represents the non-productive time (NPT) spent on a well, whereas the green portion represents the productive time (PT) spent on a well. A clear display as such gives us a clear picture on the well(s) performance as a whole. The charts for every well analyzed is presented in the Appendix.

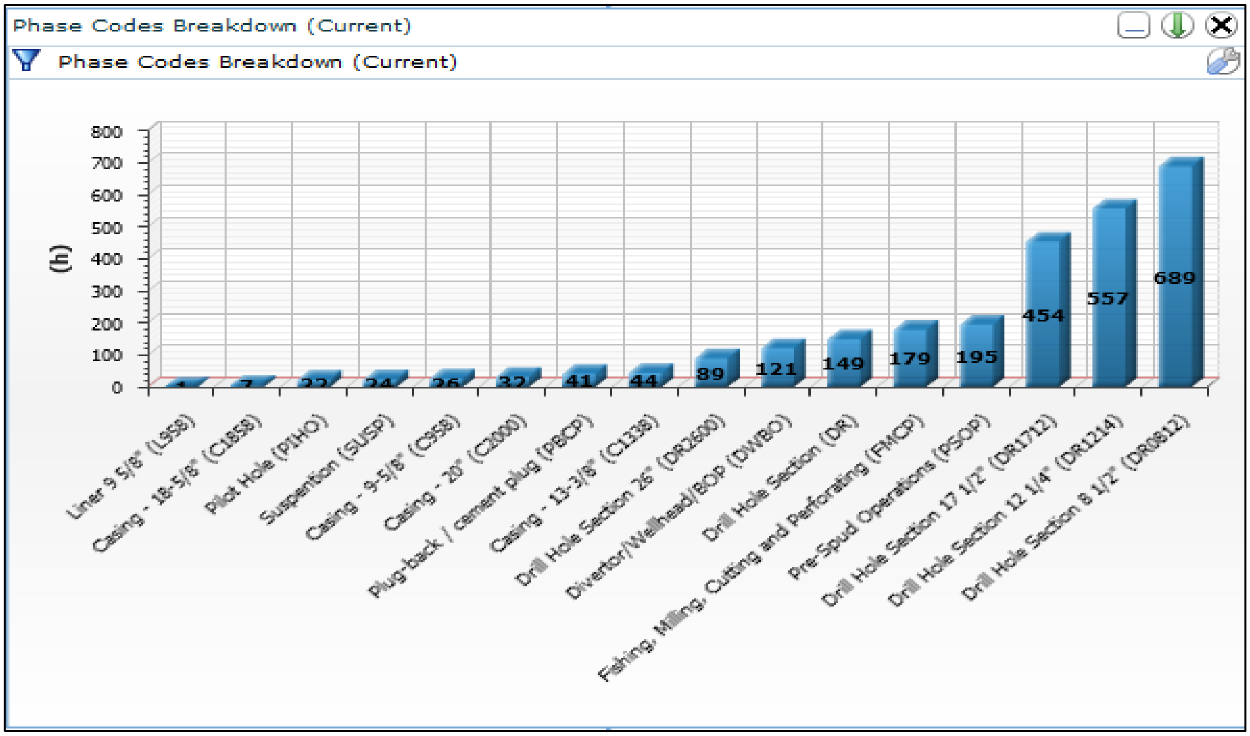

Figure 11: An Example of a Phase Code Breakdown Chart

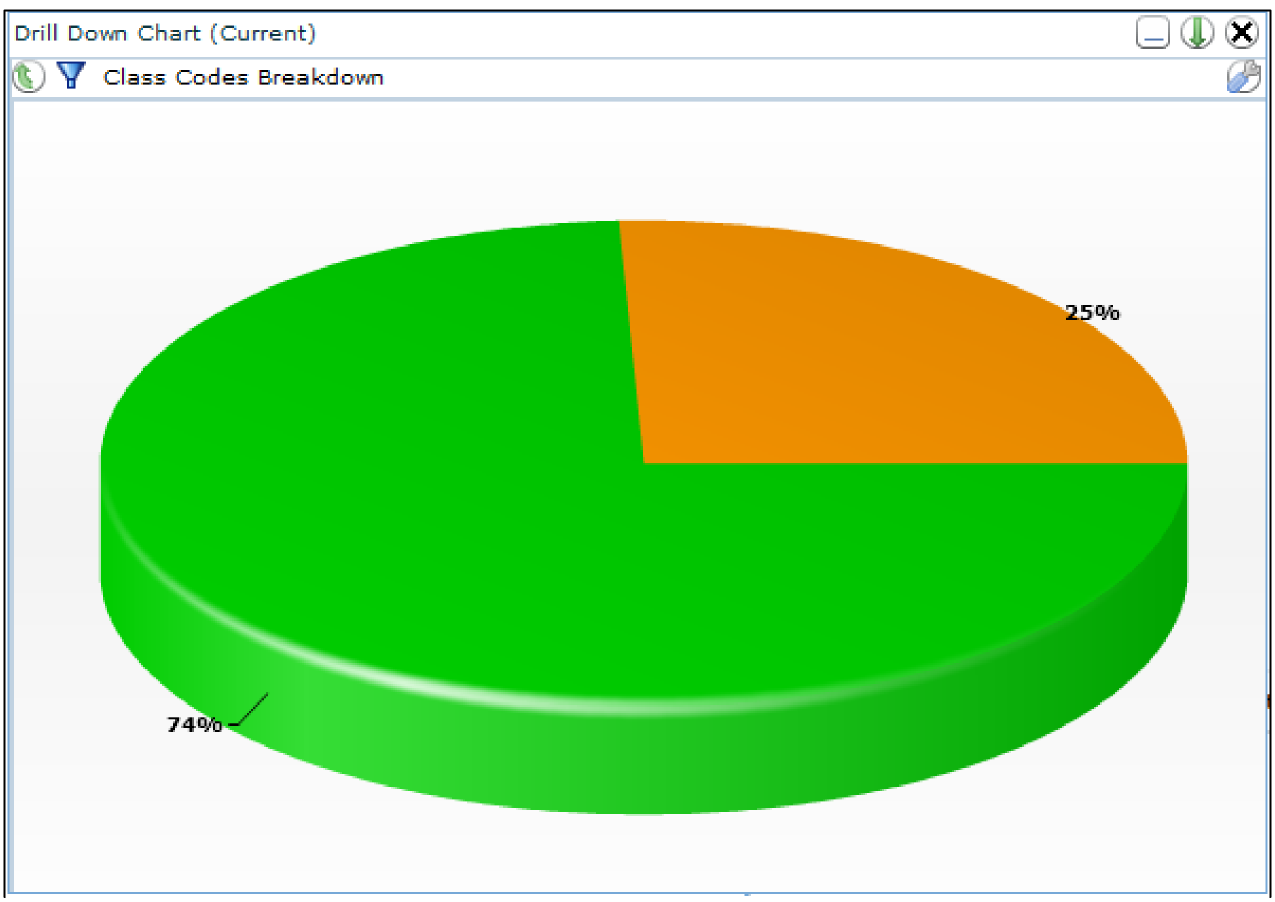

Figure 12: An Example of a Drill Down Chart Show in non-productive time in orange versus productive time in green.

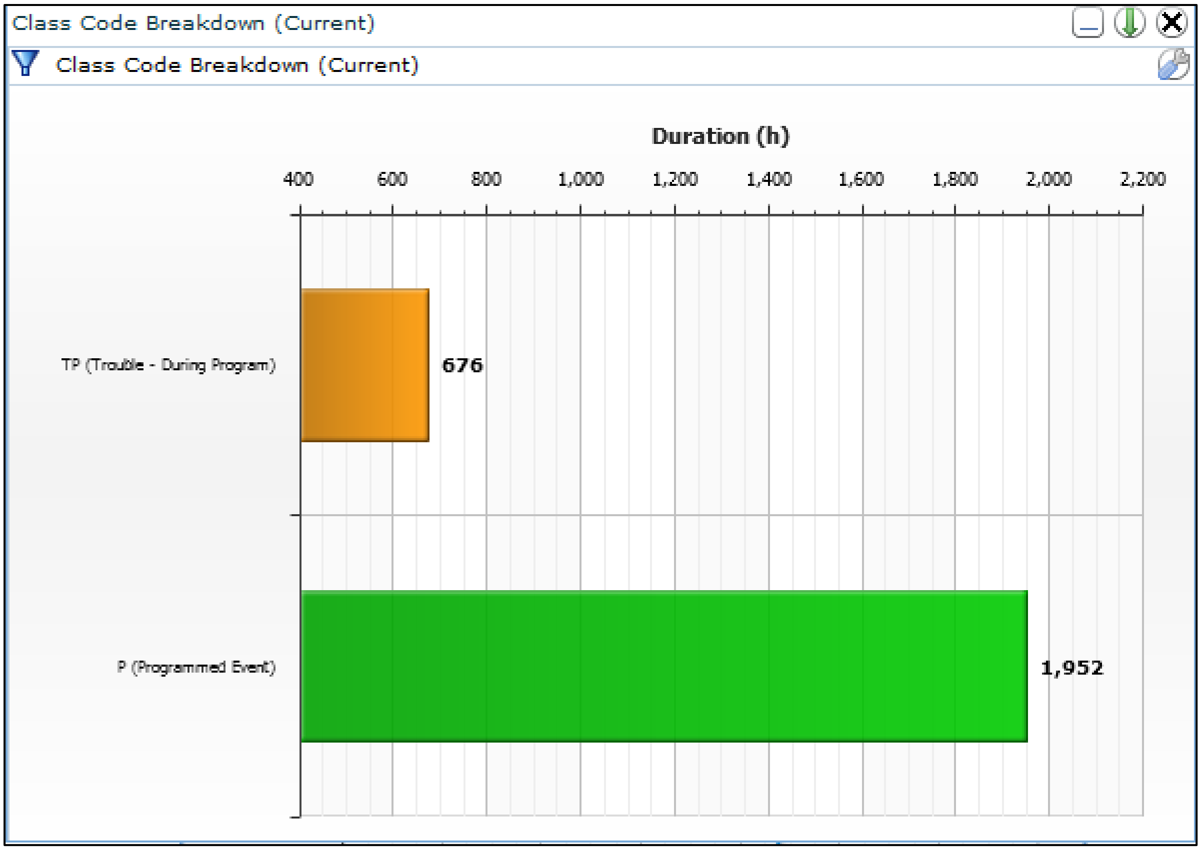

Figure 13: An example of a Class Code Breakdown Chart

Results

In this research, 42 total wells were examined. Twenty one wells from Geothermal, and twenty one from petroleum. Six problems were identified to be the driving factors for the time gap separation between the two industries.

The non-productive time (NPT) to productive time is shown for geothermal and petroleum wells in Figure 14 and Figure 15, respectively.

As can be seen in Figure 14, the non-productive time for the geothermal wells was a staggering 6,675 hours. This makes the NPT breakdown for the geothermal wells almost 21% of the total time spent drilling and completing these wells. The non-productive time amounts to 278.13 days; using an average cost of $50,000 per day equates to losses of greater than $13.9 million dollars in these twenty one wells alone. As a comparison, the NPT of the twenty one petroleum wells analyzed was 626 hours or 26.08 days (Figure 15). Using the same cost per day would equate to $1.3 million dollars, lest than 10% of geothermal. Using Figure 16 and Figure 17, the NPT per well of geothermal and petroleum (respectively) can be viewed. These charts confirm the trend of greater amounts of lost time seen in the geothermal sector.

A more specific analysis can be made by comparing the same functions performed by both industries to see if petroleum wells are being drilled and completed faster overall, with regards to productive time only. This comparison method is most helpful in describing the six identified problems previously mentioned. Figure 18 and Figure 19 show where the productive time was allocated for geothermal and oil wells respectively. Both figures show the largest portion of time was spent drilling. However, the petroleum wells were completed to depths reaching almost 14,000 feet, whereas geothermal wells only averaged a total depth of approximately 8,000 feet. This difference speaks to more than one of the specified problems. ROP is likely the greatest influencing factor.

Figure 21 shows the most efficient geothermal and petroleum wells used in this analysis. The depth drilled vs. the time taken (in days) is shown, and an enormous gap is seen between the two wells. The geothermal well took 58 days to drill and complete to a depth of 8,065 feet. The oil well was completed in 11 days to a depth of 13,250 feet. One issue to note is the difference in lithology between the two wells. Given that they were not drilled in the same target basin; however, the differences in completion time are so great, there must be other factors in play. If the same depth as the geothermal well's TD is selected (just under 8,000 feet), it can be seen that the petroleum well reached that in 4 days whereas the geothermal well took 52 days. This is 48 days more and at the previous estimated daily rig cost, would be $2,400,000 more, just in the rig cost alone.

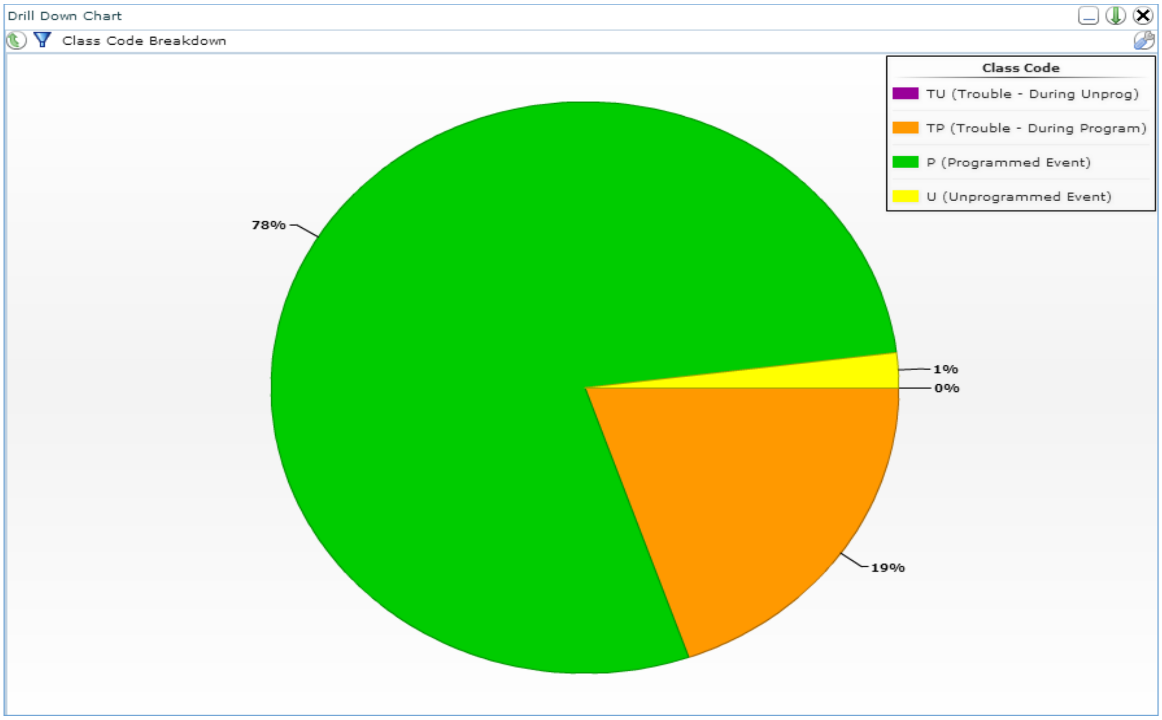

Figure 14: This is the total NPT for all geothermal wells analyzed.

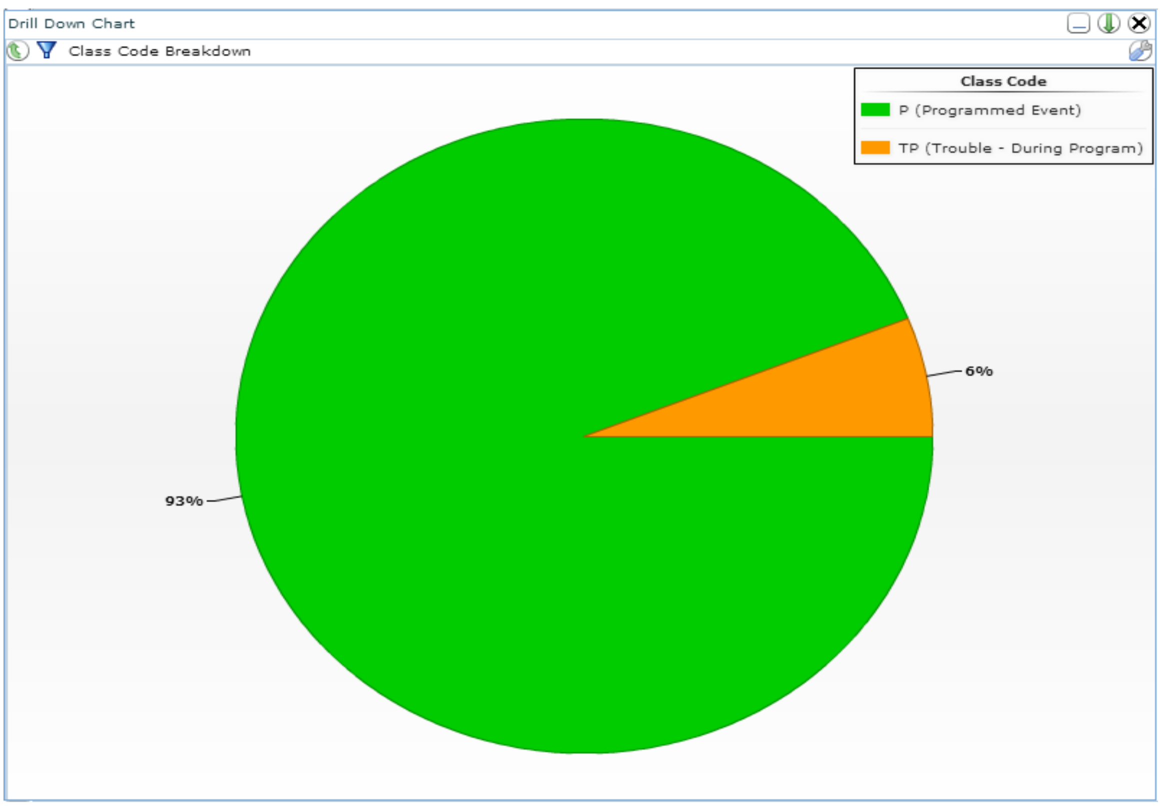

Figure 15: This is the total NPT for all petroleum wells analyzed.

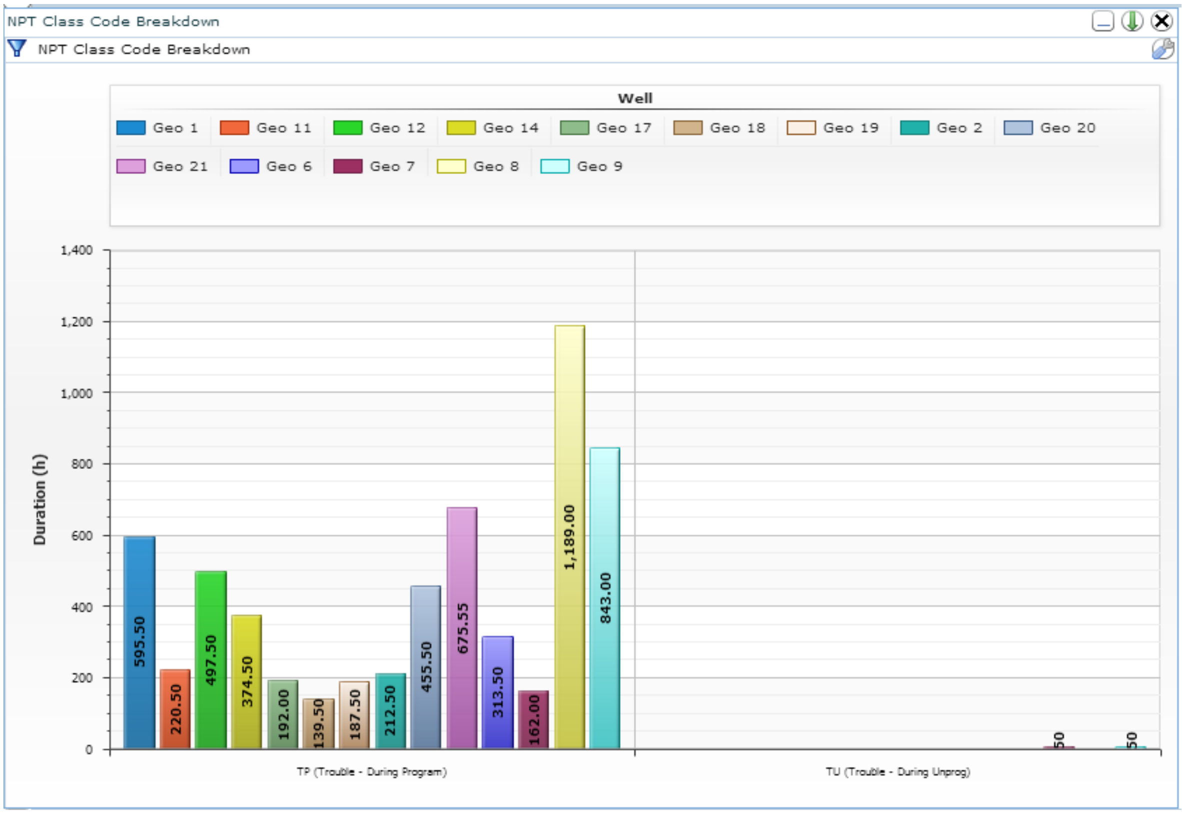

Figure 16: The NPT breakdown per well for all geothermal wells used in this study.

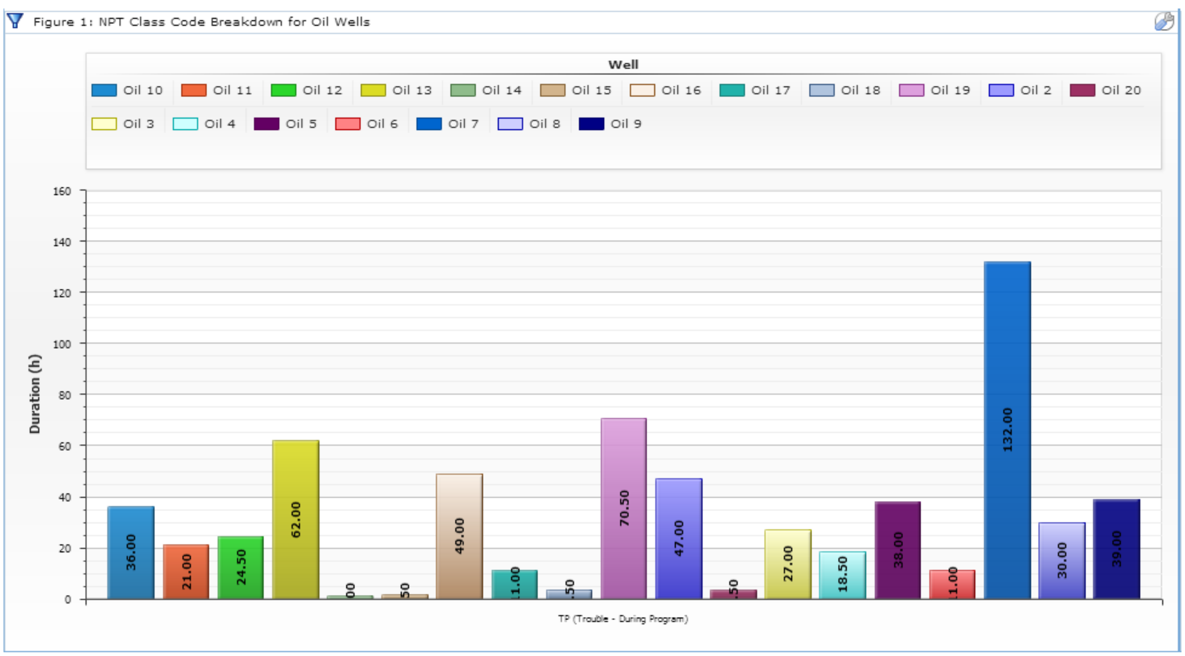

Figure 17: The NPT breakdown per well for all petroleum wells used in this study.

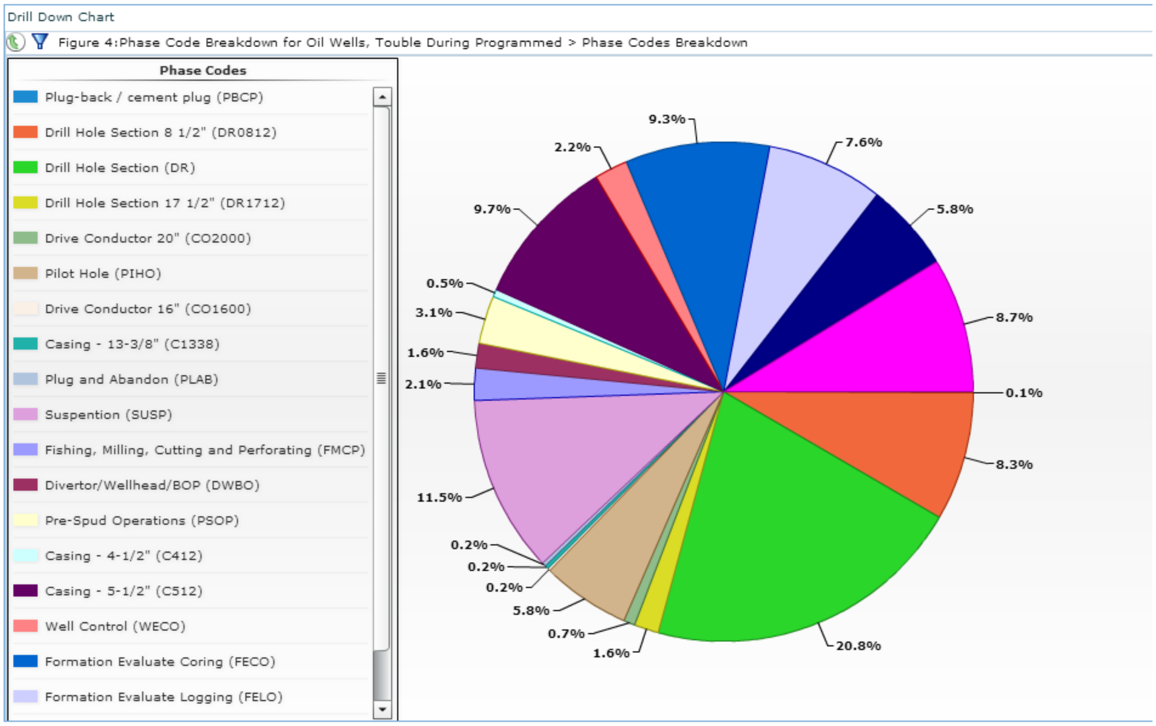

Figure 18: The productive time breakdown for geothermal wells

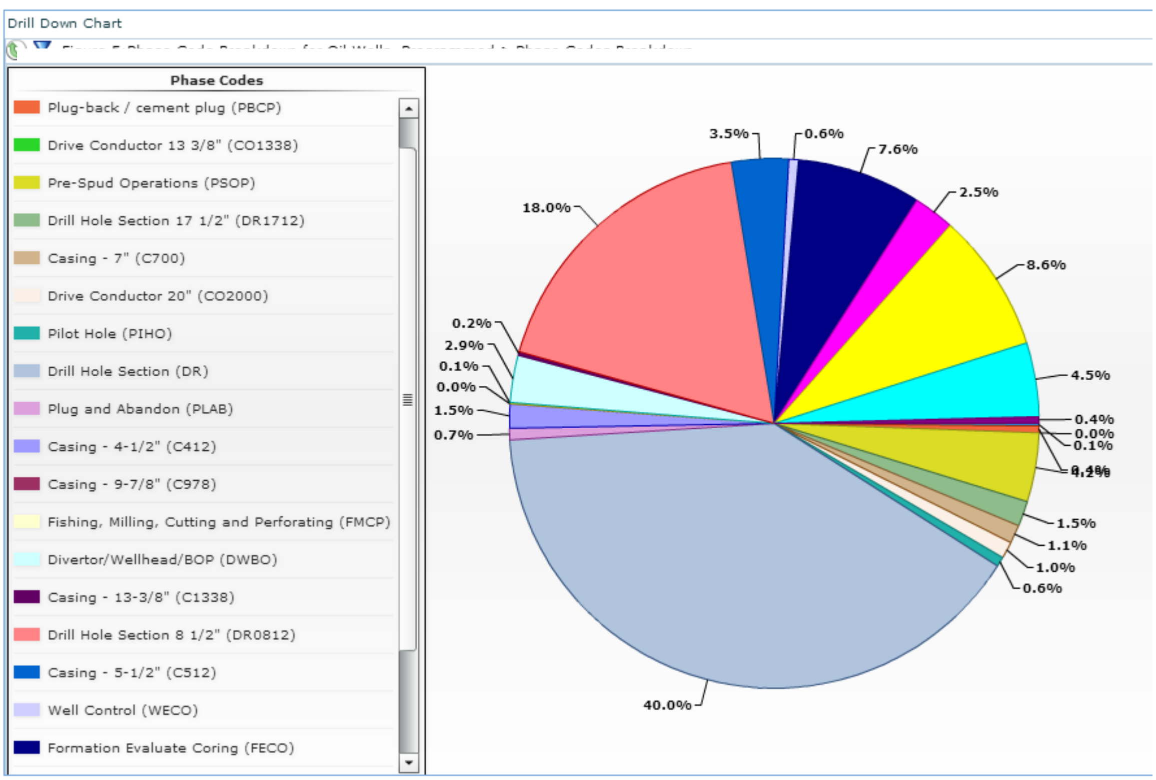

Figure 19: The productive time breakdown for petroleum wells.

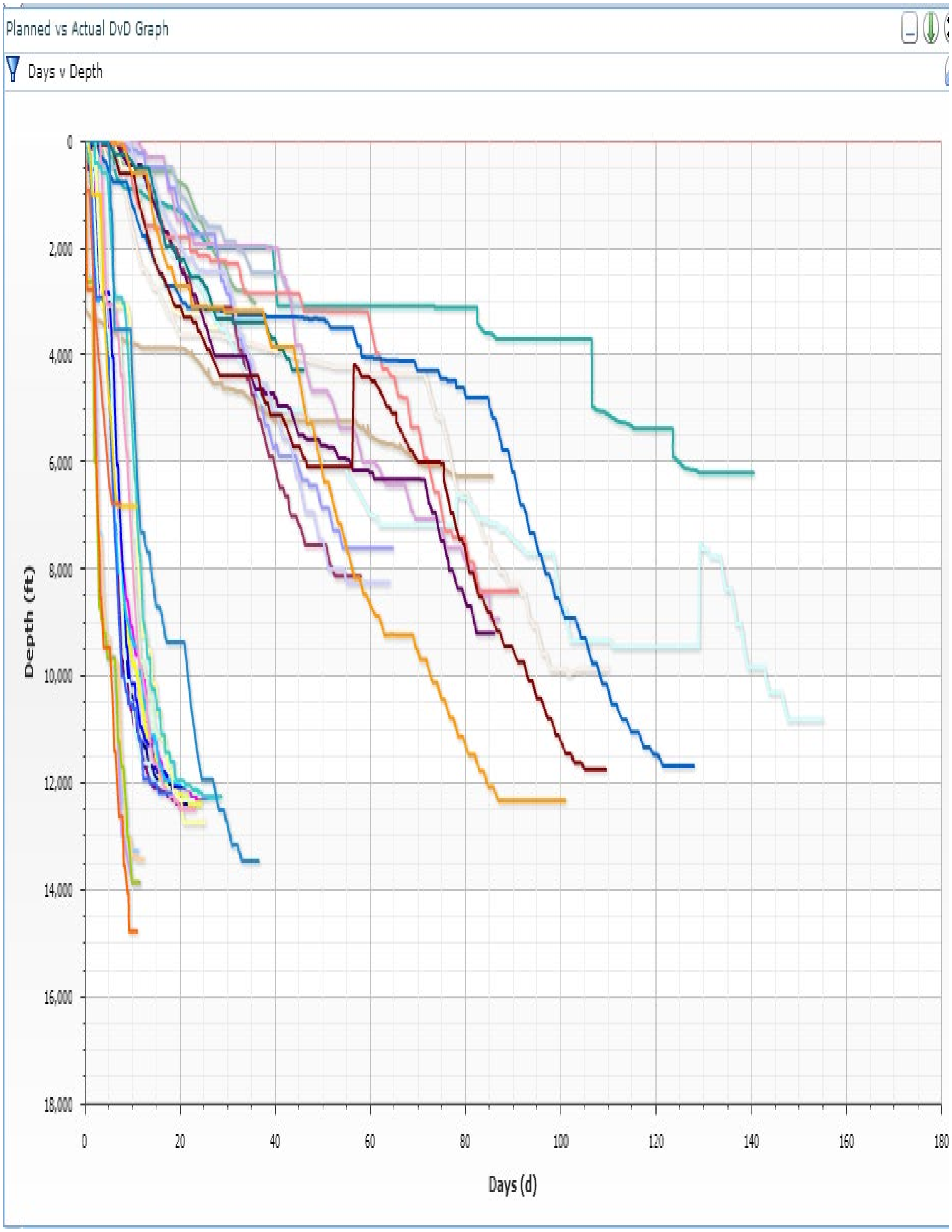

Figure 20: Days versus Depth of all wells analyzed. The differences in ROP and quantity of flat times with NPT areas of the graph make the distinction of petroleum and geothermal wells easy to identify.

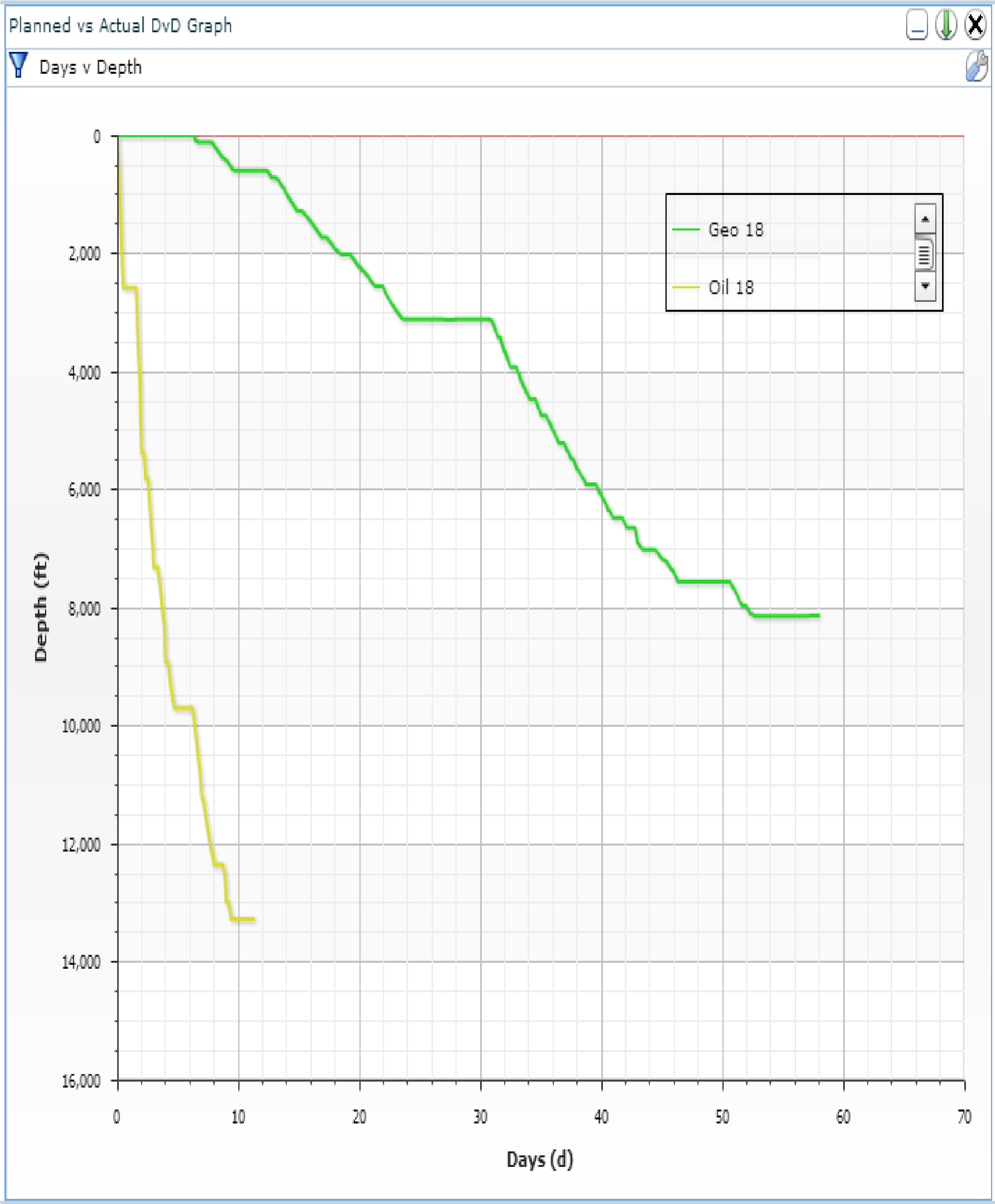

Figure 21: This shows the best in class of the 21 geothermal and 21 petroleum wells analyzed.

Potential Opportunities

Introduction

This section gives introductory information on the analysis of multiple geothermal and petroleum wells drilled in the United States in the last four years. Moreover, it gives a detailed description of the problems complicating the development of the geothermal industry. The wells analyzed were documented from four different geographic locations. None were defined as benchmark or "perfect wells", in fact, they all encountered similar issues during the drilling process. After analyzing these wells, six major problems are identified. These include lost circulation, an efficient drilling program, rig and equipment selection, cementing, rig management, and thermal complications. There are other issues but these six appear to be the most glaring issues.

Lost Circulation

One problem that is apparent in all of the geothermal wells analyzed is lost circulation. Lost circulation related issues account for, on average, 10% of the total cost of a geothermal drilling operation. These issues result from a variance of pressure between the formation and the drilling fluid column. This pressure variance is due largely to lithology and formation properties. The most common types of lithology found in geothermal reservoirs are very hard igneous or metamorphic formations such as rhyolite, granite, and volcanic tuff. These formations tend to have frequently large fractures. With a high pressure gradient in the drilling fluid column and large fractures in the formation, it is common to lose drilling mud.

The lost circulation problem was addressed in several ways, however two methods are most common; drilling with air and using Lost Circulation Material (LCM). In this analysis, the total non-productive time of lost circulation will be shown as well as the comparison of the two methods for solving this issue. In all 21 of the geothermal wells combined, 3474 total hours of lost circulation mitigation, fluid influx/control, and pumping cement plugs was found. Using the average of $50,000 a day, this accounts for a cost of $7.24MM.

There are four major sections that attributed to most of the lost circulation time; drill hole section 12¼", waiting on cement, drill hole section 17½", and cement plug. The dill 12¼" section for all geothermal wells contained 665 hours of LC, waiting on cement contained 321 hours of LC, the cement plug section contained 532 hours of LC, and the drill 17½" section contained 1,175 hours of LC. Out of all the NPT of the biggest section, drill 17½" hole, 89% was due to lost circulation. This is common trend with all non-productive time operations.

To compare the two methods for solving these problem wells Geo 18 and Geo 19 will be compared side by side. They both were drilled in the same field, had the same operator and both wells had similar ending depths. Geo 18 utilized air drilling while Geo 19 utilized LCM plugs. As can be seen in Figure 22, these two wells encountered lost circulation at similar times; this can be seen as the flat spot from day 24 to day 32 and almost all the other minor flat areas seen on the chart. Geo 18 had a significantly faster ROP, even while drilling with lost circulation. The flat area from day 46 to 51 represents a block line failure in the rig, therefore it will be neglected for this analysis. Figure 23 shows the time breakdown of non-productive time while drilling ahead for well Geo 18 and Geo 19 respectively. For Geo 18, the lost circulation is represented by the blue, and you can see that it only takes up 29% of the NPT. On the other hand, for Geo 19, lost circulation is represented by the red and takes up 64% of the NPT. This is indicative of air drilling being a much better solution. However, in Figure 11, 29% is also due to waiting on repairs which is represented by yellow. This shows that in this particular example air drilling systems aren't as stable as conventional mud drilling. To tie together lost circulation with equipment selection, the best approach as seen by the data would be to use a very reliable air drilling system as opposed to using LCM.

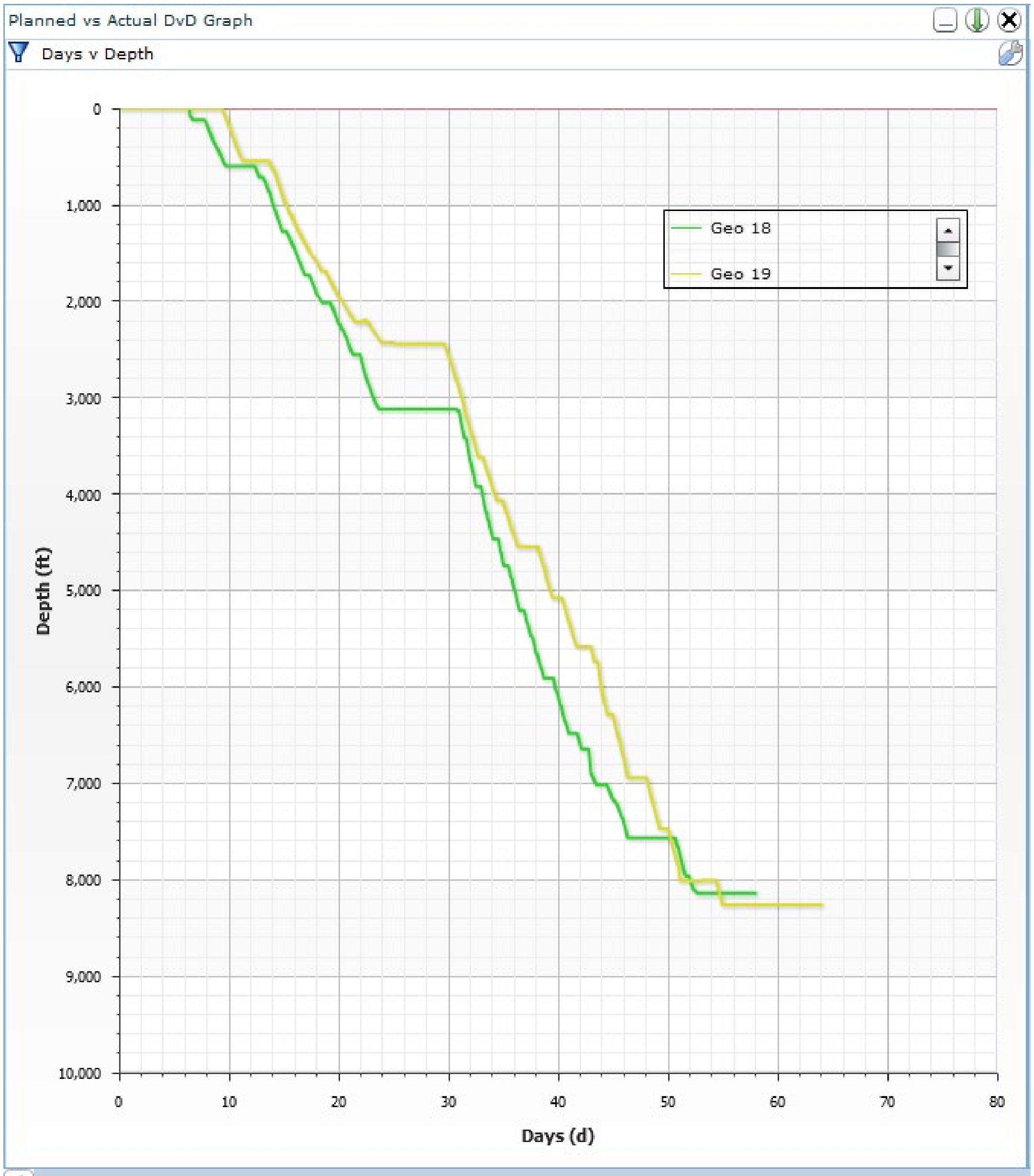

Figure 22: Comparison of Geo Well #18 and #19

There are multiple methods to combat this issue. Commonly, the first method is to pump either a cement plug or lost circulation material (LCM) downhole. The goal is to plug the fractures causing the lost circulation and regain well control. If successful, this method takes up very little time and is fairly inexpensive. However, due to the un-predictive nature of the fractures as well as how the LCM or plugs will flow downhole, this method has in general proved unsuccessful.

Another method that perhaps yields better results is under-balanced drilling. This method substitutes the normal drilling fluid with very lightweight fluids such as air. A successful example of this can be seen in an example geothermal well operation. This well encountered severe lost circulation. As can be seen in Figure 22, between day 24 and day 41, multiple attempts to pump cement plugs and LCM sweeps proved unsuccessful. As the well switched to air drilling on day 41, the lost circulation ceased. However, because the pressure in the drilling fluid column dropped so dramatically, they had to stop frequently to clean out the fill accumulating in the wellbore.

Figure 23: Comparison of NPT for Geo Well #18 (top) and Geo Well #19 (bottom)

Other less common solutions include double tube reverse circulation, drilling with lost circulation, and wellbore sealing. Further analysis of geothermal wells and the lost circulations issues associated with them will help show which techniques are best suited for geothermal drilling.

Drilling Program

Another major issue found in these wells was ROP and rig management in the way of a complete and efficient drilling program. As the cost of drilling geothermal or petroleum wells increases, research and technology groups have acted to develop processes which optimize the drilling process. Technology is allowing the development of new strategies that are replacing the previously perceived notions of what is occurring at bottom hole (BH).

In 1964 Robert Teale introduced, *The Concept of Specific Energy in Rock Drilling*, which explains clearly the relationship that "to excavate a given volume of rock, a certain theoretically attainable minimum quantity of energy will be required". In Teale's paper he also points out that "*mechanical efficiency* is a maximum when *specific energy* is a minimum". Based on these early technical assumptions, a new approach is now underway that will optimize drilling programs throughout the drilling industry. It is the use of Mechanical Specific Energy (MSE) as a tool to realize efficient drilling processes. However, a work-flow must also be established in order for there to be an efficient drilling program.

The industry's previously perceived ROP effect on drilling efficiency is such that if ROP increases, efficiency increases. This is not the case when taking into consideration the rock formations being drilled, as not all formations are equal due to varying confined compressive strengths. Therefore, it cannot be assumed that ROP has positive effects on drilling efficiency. It is also crucial that all the critical operational parameters are identified and analyzed, and only then can drilling efficiencies have the desired effects on cost. These parameters are known as *performance qualifiers* (PQ), and are identified by Mensa-Wilmot et al as:

- Footage Drilled per Bottom Hole Assembly (BHA)
- Down-hole Tool Life
- Vibrations Control
- Duability
- Steering Efficiency
- Directional Responsiveness
- ROP
- Bore-hole Quality

When project objectives are defined, the PQ's can then be assigned a level of importance and must never be analyzed in isolation as they are all interrelated. This is to say that ROP improvement should not compromise the other PQ's. According to Mensa-Wilmot et al, the factors that affect ROP are grouped into three categories:

- Planning: Hole size, well profile, casing depths, drive mechanism (PDM, RST, turbine), bits, BHA, drilling fluid and rheological properties, flow rate, HIS, and hole cleaning
- Environment: Lithology types, formation drillablility (hardness, abrasiveness, etc.), pressure conditions (differential and hydrostatic), and deviation tendencies
- Execution: Weight on Bit (WOB), RPM, drilling dynamics

Drilling efficiencies are dependent upon average ROP_{avg}, and not instantaneous ROP_i. The ROP_{avg} is based on the total interval drilled, by a respective BHA, from Trip-in-Hole (TIH) to Pull-Out-of-Hole (POOH). Mensa-Wilmot et al have suggested that should one of the following three questions be answered ***NO***, then the ROP gain will be short lived:

- Was the drilling system design (bit, BHA, drive system) designed to allow for the WOB increase?
- Can the factors affecting ROP categories accommodate the ROP gain?
- Has an efficient action (WOB increase) vs. reaction (ROP gain) relationship been established?

In these contemporary times, drilling efficiency is defined as achieving the lowest cost outcome for constructing usable wells; and, according to Mensa-Wilmot et al, achievement of operational objectives (defined by PQ's) must always outweigh the mechanical considerations (established by MSE and ROP).

However, drilling programs initiated by Exxon-Mobil, Shell, and Chevron have shown that MSE analysis is leading the way in achieving drilling efficiencies. While PQ's are important considerations, it should be noted that the range of *increased* drilling efficiencies from the use of the MSE drilling program is substantial. Again, it is important to recognize the interrelationship between the two notions.

As Teale posited, specific energy can be defined as "the amount of energy required to destroy a given volume of rock". It also applies to the Mechanical Specific Energy (MSE) which is required to destroy the same volume of rock. The MSE model has many advantages while it is used in a real-time drilling operation because it can address many important variables which achieve drilling efficiency. It can be used to predict and analyze the power required for a specific bit type in a given rock for a specific ROP. The operating parameters discussed above can be adjusted to reach a maximum ROP value without damage to the any of the components of the BHA or drill string. When fluctuations in the MSE are acknowledged, it is then determined which of factors that affect ROP require adjustment in order to maintain drilling efficiency. MSE identifies the dysfunction within the operational parameters so that they can be either adjusted or redesigned.

Drilling programs such as the Fast Drill Process (FDP) by Exxon-Mobil has prompted the practice of MSE surveillance and is incorporated into a track along with WOB, RPM, and ROP. This allows a driller to monitor the MSE during the drilling process. As Dupriest et al point out in their SPE technical paper, *Maximizing Drill Rates with Real-Time Surveillance of Mechanical Specific Energy*, "There should always be awareness that the MSE may contain inaccuracies and should only be used as a trending tool."

MSE surveillance is quickly becoming an invaluable tool to monitor the changes in drilling efficiency in real-time, and allows optimum operating parameters to be identified as well as providing quantitative data needed to cost-justify design changes. Thus, as Dupriest et al offers, "The manner in which the bit is run is more important than which bit is run." An important point to acknowledge is the range in which a bit is efficient, and this can be represented on a graph plotting ROP to WOB. There are three regions of interest and the second being designated as the most optimal region. Dupriest et al highlight these areas below and is shown in Figure 24.

In determining ROP, the factor that creates inefficiency (founder) and the factor that limits energy input are the targets for mitigation. In general, if the MSE value is rising then the system is becoming inefficient and is in need of adjustment. This is relevant to Teale's discovery that the MSE is consistent with the rock strength. Several limiters have been sighted which cause founder on a regular basis and are bit balling, bottom hole balling, and vibrational founder; however, the largest source of error is drill string friction between the pipe and borehole. This causes torque values to increase and the, "MSE value will exceed the rock strength by several hundred PSI, yet the bit is operating efficiently and the high values are due entirely to drill string friction". According to Dupriest et al, "This issue will be resolved to some degree when software is developed to utilize down hole data. However, even with down hole data it's likely that the MSE curve will continue to be used primarily as a trending tool".

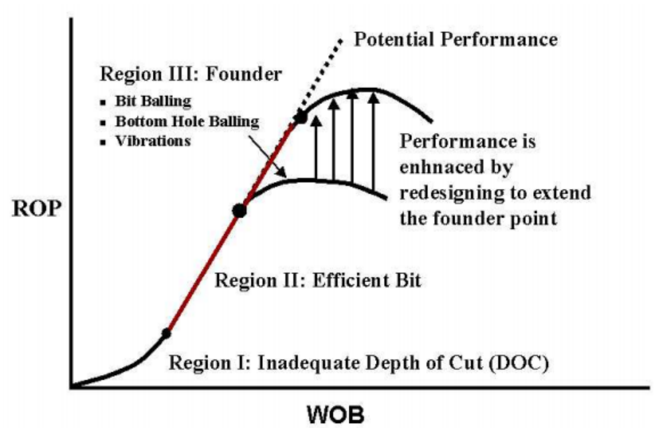

Figure 24: Weight on bit versus Rate of Penetration

- Region I, performance is constrained by inadequate depth of cut (DOC) due to low WOB.
- Region II of the drill-off curve starts when the DOC becomes adequate for the bit's performance to stabilize
- Region III begins at the founder point where a condition develops in which the transfer of energy from the bit to the rock is constrained

Bit balling is the accumulation of material on the surface of the bit which in turn inhibits energy transfer to the rock, and is sighted as the easiest to detect of all the founder points. Hydraulics have been the answer to address the issue, but the process does not entirely mitigate the founder, it only extends the founder to a higher ROP and WOB. Dupriest et al mention the opportunity that, "Real time surveillance of MSE Weight-Tests has enabled the relationship between hydraulics and ROP to be quantified, with potential implications in equipment contracting".

Bottom hole balling is the condition where material has accumulated on the bottom of the hole inhibiting the transfer of energy to the rock. This is a typical issue with insert bits, but PDC bits can address the issue. The MSE value becomes extremely high and the ROP decreases drastically. Again, the trend has increasingly been used to detect the founder and action is taken to return to optimal efficiency.

Vibrational founder has been the most difficult of all to detect. Dupriest et al suggest, "MSE field data suggests that Vibrational founder may be uniformly worse in Non-aqueous fluids (NAF), leading to the speculation that the higher friction in water-based mud helps to dampen the excitation of the string". Vibrational founder becomes destructive when WOB is increased to mitigate whirl in the drill string. The result is a substantially larger borehole and a damaged bit. Again, vibrational founder tends to increase the MSE value; however, due to drill string fiction and drill string torques the value may be obscured.

Rig Management

According to the IADC conference paper entitled "A Global Drilling Organization: The Role of the Drilling Professional" by George F. Boykin, drilling has been defined as "the management of drilling completion activities, consistent with the corporation's success factors and financial goals**."**

The first large issue linked to rig management in geothermal wells is the poor cost monitoring and analysis. A potential solution to this problem would be again, the IDS Datanet Software system or something similar just to keep track of expenditures (not for accountants but for engineers). Apart from helping to record the operational data of a well such as drilling and workover, the example software provides a facility to record and store the daily costs of a well. It can be used to create days for an operating well before tabulating activities for a particular day. In the information sheet provided (below the service companies' blank text boxes), there is an option available to record daily cost. By using that function, well operators/engineers/data recorders wouldn't have to face the trouble of missing crucial cost information of a well. Also, there is a space to locate the Authorization for Expenditure (AFE) Number, so that software could display the original AFE amount. Using all that information keyed in the software, it makes it easy for the software to punch out useful and insightful results afterwards. Total cost versus AFE comes in handy when it is required to evaluate the well's performance and compliance to the allocated amount of money for operations. The cost/depth would be valuable to detect the exact zone(s) which has caused troubles, so that well operators could troubleshoot before it is too late. However, the main idea is to utilize computer based data storage instead of handwritten costs tabulation to avoid unexplained rise in costs.

After analyzing well data plotted in IDS Datanet Software, two major rig management issues can be recognized. The first is poor spending and data tabulation. For example, in one example well, there were many instances encountered with unexplained costs. Days 46 – 57 had an unexplained rise in daily cost of $2,132, and days 60 – 63 had a similar rise in daily cost of $2,100 which was also unexplained. The second issue is missing data. The geothermal wells analyzed contain many data holes in the daily drilling reports including information such as bit records and mud weight.

Geothermal wells 13, 16, and 17 contain many data holes in the daily drilling reports including information such as bit records and mud weight. A potential improvement for being able to improve and learn in rig management is to properly and completely document the activities on the rig site. For example, the use of the *Mobil Drilling Data Center* (DDC) can help with not only post-analysis but with real-time operations. This drilling management system has been in practical operation for the past thirteen years for the petroleum industry. It focuses on facets such as management commitment, client alignment and partnerships with service companies.

DDC has always maintained access to data in usable (electronic) form and real time services. Some of the data available for this project was in the form of photocopied handwritten reports. Additionally, many of the handwritten reports were lacking important data or were illegible. This can make post-drilling data analysis difficult, to say the least. Our petroleum exemplar operator is an example of a drilling company which has their data tabulated in both written form and electronic spreadsheets. This gives the company or third parties the ability to analyze and manipulate the data for future improvements. Software such as *IDS DataNet* or *DDC* is available to help organize daily drilling information in a concise format while avoiding gaps in data.

Another issue associated to rig management in geothermal wells is the missing data in daily drilling reports (DDR). A potential solution to this problem was found in a technical paper used for the 2000 IADC/SPE Asia Pacific Drilling Technology conference that happened in Kuala Lumpur, Malaysia. Entitled *"Performance Improvement Techniques Used on Goodwyn A Platform"*, S.P Dolan and his team have explained a rather astonishing concept known as PIGS**.** An abbreviation for Performance Improvement Group, PIGS is a group of specially assigned workers whose main task is to locate large holes between the planned and actual performances and fix it. A major suggestion to the geothermal drilling industry would be to adapt the concept and produce a similar team in order to fix the missing data issue. This is because a well's performance could not be studied to perfection when data goes missing. A well might perform fine but certain data holes could affect the data study and have the potential to confuse fellow engineers and operators. By forming a specialized team such as PIGS to analyze and make sure of the data's existence and accuracy, major mistakes could be avoided.

Finally, a choice of words and acronyms used in the drilling reports is a problem associated to rig management as well. A potential solution to this problem would be to adapt certain verified or official glossary terms to describe rig operations. For example, Schlumberger Oil Field Glossary (www.glossary.oilfield.slb.com) and Envestor First's Acronym List (http://envestorfirst.com/oil-research/oil-field-acronyms) provide a comprehensive list of oil field acronyms, terminologies and explanations that are commonly used and applicable to operations taking place in the geothermal drill sites as well. The reason to follow this official list is to make activity descriptions uniform and coherent with every other wells, be it the ones that belong petroleum or geothermal. It makes data analysis easy, fast and easily comprehendible and accessible.

Geothermal Well Cementing

A drawback hindering successful geothermal well completion is effective cementing of wells in high temperature and high pressure conditions (HTHP). The main objective of cementing a geothermal well is ensuring the entire annulus is filled with properly formulated cement which can withstand HTHP conditions. Many geothermal wells are characterized by fractures where loss of circulation is problematic and requires a careful design of the cement slurry, proper casing placement, and consideration of the use of design chemicals to seal off loss of circulation zones. In addition to the design implications, lab testing is essential in the determination of whether the designed cement can withstand bottom-hole temperatures and pressures prior to the commencement of the cement job. Efficient cementing jobs must be well organized and all considerations addressed to realize a successful job. Once the cement slurry has set, wire-line tools should be deployed to inspect the cement job along the casing to ensure the integrity of the cement bond to the casing and formation.

A successful cementing of a geothermal well requires that an in depth well analysis is completed of the section to be cemented. The analysis will reveal information such as temperature, formation pressures, sulfur content, and loss of circulation zones. The design of the cement slurry for the each well is unique to the well as no two wells are characterized with the exact attributes.

"The top priority in achieving a successful cement job is to displace all the mud from the annular section to be cemented and the mud cake on the annular wall". This step in the cementing process is crucial as cement applications require the surface be absent of foreign materials for proper bonding. Bett goes on the mention that prior to running the casing and cementing, the drilling fluid should be conditioned to exhibit 'easy-to-remove' properties including low fluid loss, thin rheological properties, and a flat gel profile. This is achieved with the use of mud-thinners and deflocculants. Another point to be made is that once mud conditioning has been completed, the cementing process should begin no longer than fifteen minutes later.

When conducting geothermal well cementing, proper Bottom Hole Circulating Temperature (BHCT) must be maintained at all times. As a reference, the BHCT typically used for cement slurry design are found in API Specification 10. In order to use the API BHCT correlations, the average static temperature gradient must be known. Cementing temperature conditions are important because BHCT affects slurry thickening time, rheology, set time and compressive strength development.

The final step prior to the start of the cement job is to lower the casing into position. Centralizers must be placed properly to enable the slurry to pass through the annulus without fail. According to Bett's studies, the rule of thumb is to allow a minimum casing stand-off of 70% through critical sections. Stand-off can range from 0% (casing against the annulus wall) to 100% (casing perfectly centered in the annulus).

The four cementing practices for geothermal wells are: Single-Stage cementing, Inner String (Stinger) Cementing, Reverse Circulation Cementing, and Two-Stage Cementing. The single-stage cementing is a good option for shallow wells which do not require much time to complete since the slurry would be more exposed to heat as it is displaced through the casing. Inner-string or stinger cementing process allows for the slurry to reach Bottom Hole (BH) without much exposure to differential heat. Since temperature is an issue in geothermal well cementing, it stands that the Stinger cementing process is good practice. The drawback is tripping drill-pipe (the stinger) is Non-productive time (NPT). Reverse circulation cementing is the most optimal of the methods for cementing wells with loss circulation problems. "Reverse circulation allows for a wider range of slurry compositions, so heavier or more-retarded cement can be placed at the lower portion of the casing, and lighter or accelerated cement slurry can be placed at the top of the annulus". Since gravity is working in favor of the descending slurry, the hydraulic horsepower is reduced as well as fluid pressures. Two-stage cementing is rarely used in the cementing of geothermal wells because special equipment needs; however, "it is used for weak formations that cannot handle high hydrostatic pressure of large columns of slurry".

Slurry design must be conducted on a case by case approach for geothermal wells. The design is affected by well depth, BHCT, BHST, type of drilling fluid, slurry density, pumping time, quality of mix water, fluid loss control, flow regime, settling and free water, quality of cement, dry or liquid additives, strength development, and the quality of lab cement testing and equipment. "Cement system design for geothermal wells differs from those for conventional high temperature Petroleum wells in the exclusive use of silica flour (15 μm) instead of silica sand (175-200 μm) and the avoidance of fly ash as an extender (light weight additive)". Bett reveals that Portland cement, manufactured to API specification, typically

API Class A or API Class G cements, are now commonly utilized in geothermal well cementing. Portland cement is essentially a calcium silicate material, and the most abundant components are tricalcium silicate (C_3S), dicalcium silicate (C_2S) and tricalcium aluminate (C_3Al). API Spec 10A classifies cement used in well cementing into the following common classes:

Class A used when special properties are not required. Available only in ordinary (O) grade
Class C used when conditions require high early strength, and are available in O, MRS, and HRS grades
Class G used as a basic well cement, and available in MSR and HSR grades; should not be mixed with anything other than water or calcium sulfate or both during the manufacture of class G
Class H used as a basic well cement and available in MSR grade only; should not be mixed with anything other than water or calcium sulfate or both during the manufacture of class H
There are other API classes; however, they are either rare or obsolete.

Many additives other than silica flour must be incorporated into the slurry design and include: retarders, lightweight additives (extenders), friction reducers (dispersants), fluid loss control additives, loss of circulation additives, anti-foam additive, accelerators, identification colors or radioactive materials. The most common retardant is calcium lignosulfonate – 0.1-0.5% BWOC, but synthetic polymers, organic acids, and borate salts are also utilized. In cases where the slurry density outweighs the fracture strength of the formation, Wyoming bentonite – 2-16% used as an extender, ensures that no free water evolves during cement set-up since it holds 16 times its volume. Most common fluid loss control additives are Organic polymers – 0.5 to 1.5% "By Weight of Cement" (BWOC) and CMHEC – 0.3 to 1.0% BWOC. Loss of circulation due to induced or natural fractures are best remedied by Mica flakes, and have proven to function adequately, whereas traditional LCM materials used in drilling muds should be avoided. Calcium chloride ($CaCl_2$) – 1.5 to 2.0% BWOC and Sodium Chloride (NaCl) – 2.0 to 2.5% BWOC are the most commonly used accelerators.

Cement mixing is done either one of two methods, conventional jet mixer or recirculation mixer. Recirculation mixer is the more commonly used mixer today. The measurement of the following parameters for the cement job is required: mix water, cement blend, flow rate, pressure, and slurry density. Six major performance properties must also be tested: thickening time, slurry density, free water, fluid loss, compressive strength, and rheology.

The new slurry techniques include: Fibre-reinforced cement slurry, hollow microspheres cement slurry, and foamed cement slurry. The fibre-reinforced slurry involves the use of 13mm brass-coated round steel fibers. Hollow microspheres can bring the density down to as low as $0.96 g/cm^3$, but is quite costly to use. Foamed cement slurry is a great alternative in geothermal wells as the cost allows its use; furthermore, it creates stable lightweight slurry, with low permeability and a relatively high compressive strength compared to conventional slurries. However, foamed cements are challenging to manage and stability is an issue as shown by the Macondo well.

In short, the cementing of a geothermal well begins with proper mud conditioning, and ensuring the well itself has been prepared to receive the cement job. This requires a sound analysis of the wellbore to be cemented on a case by case analysis. Centralization of the casing is essential as well as the use of the appropriate casing which can handle the ambient conditions. The slurry design must be proven in lab tests prior to the execution of the job to ensure the proper ingredients are performing as designed for the particular geothermal well. All materials and equipment should be accounted for on site, and experienced personnel should all be present prior to the start of job. Once the job is completed and the BWOC has passed, a thorough inspection should be conducted to ensure the cement job integrity.

Rig and Equipment Selection

Equipment integrity and selection are major problems in geothermal The issue is exemplified in one geothermal drilling project costing more than $80 million dollars. Neglecting to select the right tools and equipment undoubtedly contributed to the failure of this well. In the IADC reports analyzed for this well, more than fifty days of well operations included repairing the top drive or servicing the rig or its associated components (hydraulic lines, mud pumps etc). This well also had atypical rates of penetration during the drilling process. Although many factors influence ROP, rig selection will play a critical role in its improvement. Due to an attempt to keep initial capital investment low in geothermal drilling, it is believed that "Cheap Drilling" is an effective method to keep costs down. This method seems to cost geothermal drilling companies much more than it saves. A typical petroleum well of comparable depth can be drilled and completed in fifteen to thirty days and is influenced by proper rig selection.

Moreover, proper equipment selection as a whole is necessary to keep total capital investment low. Given that the resources of the geothermal industry pale in comparison to petroleum industry, using the right tool for the job can be an enabler for effective drilling operations. If a geothermal well, such as the aforementioned well, costs roughly $60,000 a day and can be completed in one third the amount of time, a saving of nearly 102 days in that example. With these costs spread over more than one hundred days, a total of more than $6,200,000 could be saved, not to mention the maintenance expenses needed to repair the rig. This wasted cost could have been invested in a more efficient and effective rig. It's clear that a screw driver can be used to hammer-in a nail, however, how effective would it be over a purpose built hammer or even a nail-gun?

Bit selection appeared to be an issue in some of the wells analyzed. Again, in the aforementioned well, multiple tricone roller bits were used which are rated for medium-hardness formation. In the geothermal industry, the target formation are typically highly fractured igneous or metamorphic reservoirs ; this lithology is very hard (of Mohs hardness of 7 and above) and cause excessive bit wear and low rates of penetration when using the incorrect bit. Using proper bit selection can increase ROP by up to four times by optimizing weight on bit, pressure distributions across the area of the bit, bit hardness/formation selection and torque on bit.

Another influencing factor in the differences between geothermal and petroleum wells were the choice of rigs. Through the preliminary research, it was found that many geothermal wells are drilled using older, and less advanced rigs to save upfront cost. However in using a less costly rig, more problems were encountered while drilling. A significant portion of time was lost due to rig repairs and inefficiencies with rig operations. The geothermal rigs had suspensions, in part due to maintenance of rigs and waiting on repairs for 884 total hours. Another factor the rigs could play in the total non-productive time spent on the geothermal wells can be seen in the large quantity of problems encountered while drilling, which is directly influenced by the rig specifications and capabilities.

Today, most petroleum rigs are “purpose” built to run lean and fast. They also have all of the capabilities for monitoring on and off site, they are electric giving them the ability to have infinite variability in operating parameters, top drives for circulating in and out of the hole, self-skidding capability, mechanization, some automation, and a safe working environment (such as Iron Roughnecks keeping people off the rig floor as an example). The expense pays off in the long run.

Also, it would appear that the overall time for drilling and completion operations were greater for geothermal wells when compared to petroleum wells. Just comparing the time taken to drill and complete 21 geothermal wells against the time taken to drill and complete 21 petroleum wells show a total of 30,906 hours as opposed to 10,349 hours. It should also be noted that the geothermal wells spent 6,675 hours of non-productive time, when petroleum wells only were seen to have 626 hours of NPT. This is less than 10% of the geothermal industry.

The specific timings of these inefficiencies as relates to choice of rig and equipment was difficult to analyze due to lack of complete data for the rigs and other on-site equipment used in the operations analyzed; however when comparing productive time for each industry, 24,231 hours were needed for the geothermal wells and only 9723 hours were needed for the petroleum wells. This, in part, is due to the less than ideal rigs found in operation in the geothermal industry.

Another major issue found in these wells was ROP and rig management in the way of a complete and efficient drilling program. As noted earlier in this section, the use of MSE is improving operations. Based on these early technical assumptions, a new approach is now underway that will optimize drilling programs throughout the drilling industry. It is the use of Mechanical Specific Energy (MSE) as a tool to realize efficient drilling processes. However, a work-flow must also be established in order for there to be an efficient drilling program.

Efficiency While Drilling Modeling

In an effort to gauge the efficiency of rock penetration, the Mechanical Specific Energy (MSE) and the Rock Strength (RS) at instantaneous depth intervals were examined. MSE was determined using an equation provided in Teale’s paper.

The mud and well log data of Geothermal Well 13 was digitized and used to model MSE/RS for a given depth interval. Instantaneous Rate of Penetration (ROP), Weight on Bit (WOB), Bit Diameter, Depth and Lithology were determined using the digitized mud and well log data. Unfortunately the data provided did not include RPM and Torque which are critical variables in MSE determination. The model produced uses RPM and Torque as independent variables. The purpose of the model was to represent potential RPM and Torque value bundles which would result in a MSE/RS ratio of 1 to 3. Essentially; the data points graphed indicate a specific RPM and Torque value at which MSE/RS would equal 1 to 3. Thus the more values graphed at a specific depth indicate a higher potential for efficient drilling given the provided drilling data.

Assumptions to be made from produced model

The model provided insight into the probability of efficiency but not an actual efficiency determination. The model does however demonstrate that at shallower depths there was more probability for efficient drilling than at deeper. This determination can be made by observing the larger cross-sectional area at which the model takes at given depth.

The model's shape begins to taper as the depth increases; this is because there are fewer RPM & Torque value bundles which would result in efficient drilling. The model presents sudden changes in the cross-sectional area, it is at these 'drop off points' the lithology changes.

Figure 25 through Figure 28 identify the importance of model shape and efficiency probability. This particular model demonstrated that at shallower depths there was a greater potential for an efficient drilling operation given the WOB, ROP, Bit Size and Lithology used. At greater depths however the potential for efficient drilling is narrow as evidenced by the narrow rpm to torque.

Scaling the model with the data provided gave insight into the torque and RPM capabilities that the rig should have had to accomplish efficient drilling. The model was designed to only identify RPM and Torque values which result in efficient drilling; this characteristic allows for the scaling of the model to gauge a rigs potential. Scaling the model essentially allows for the study of rig capabilities, in this case RPM and Torque, and its potential of drilling efficient. Scaling the model down is the equivalent of reducing RPM or Torque capabilities while scaling up does the inverse.

Digitization of Well & Mud Log Data

The efficiency model was produced using digitized well and mud log data. The data was digitized by hand using the rolling averages of each variable (ROP & WOB) at depth intervals of 50'. The Rock strength was determined using the overall lithology given in mud log data and empirical data of said rock.

ROP is another problem faced by the geothermal drilling sector. As discussed in the opening paragraph of this report's results, differences in ROP can be seen in Figure 10. All the wells analyzed can be seen in this Figure, and it is apparent the difference in both NPT (flat spots) and ROP (slope) of the drilling curves for geothermal and petroleum wells. The furthest left grouping is Petroleum , and the right grouping is geothermal wells.

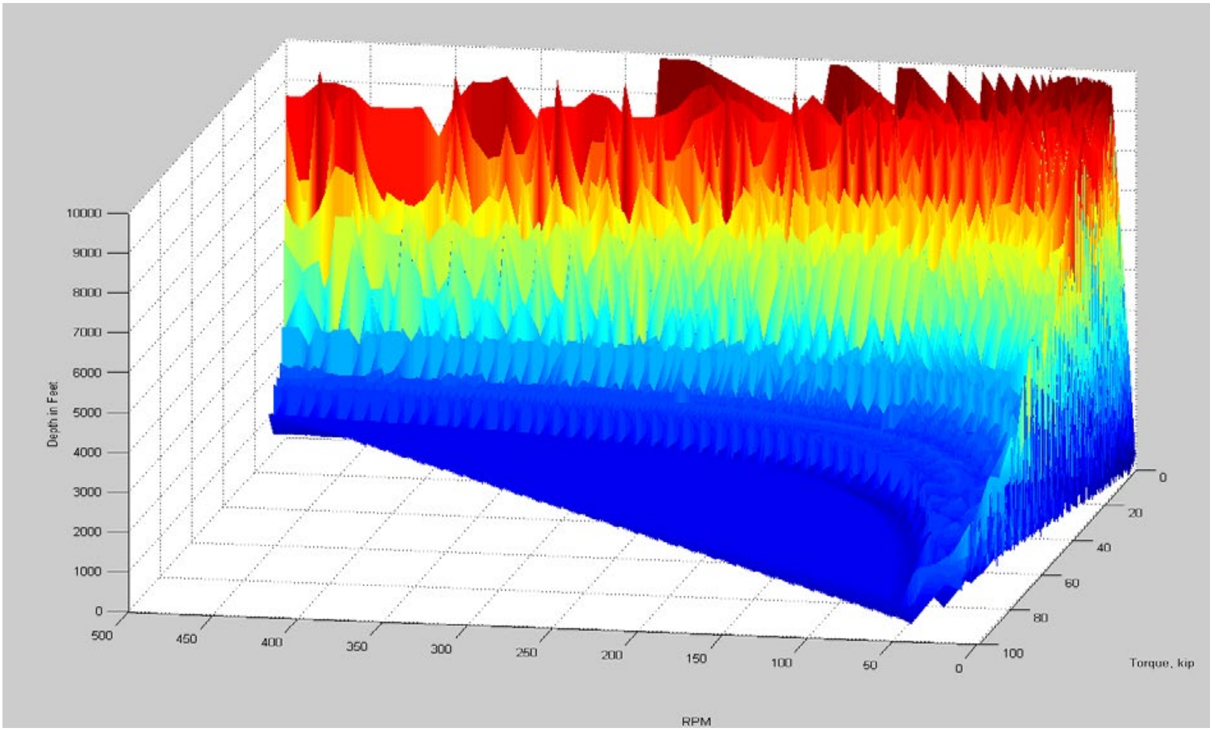

Figure 25: Represents a produced model of MSE/RS at 1 to 3, over a range of RPM, Torque Values and Depth interval.

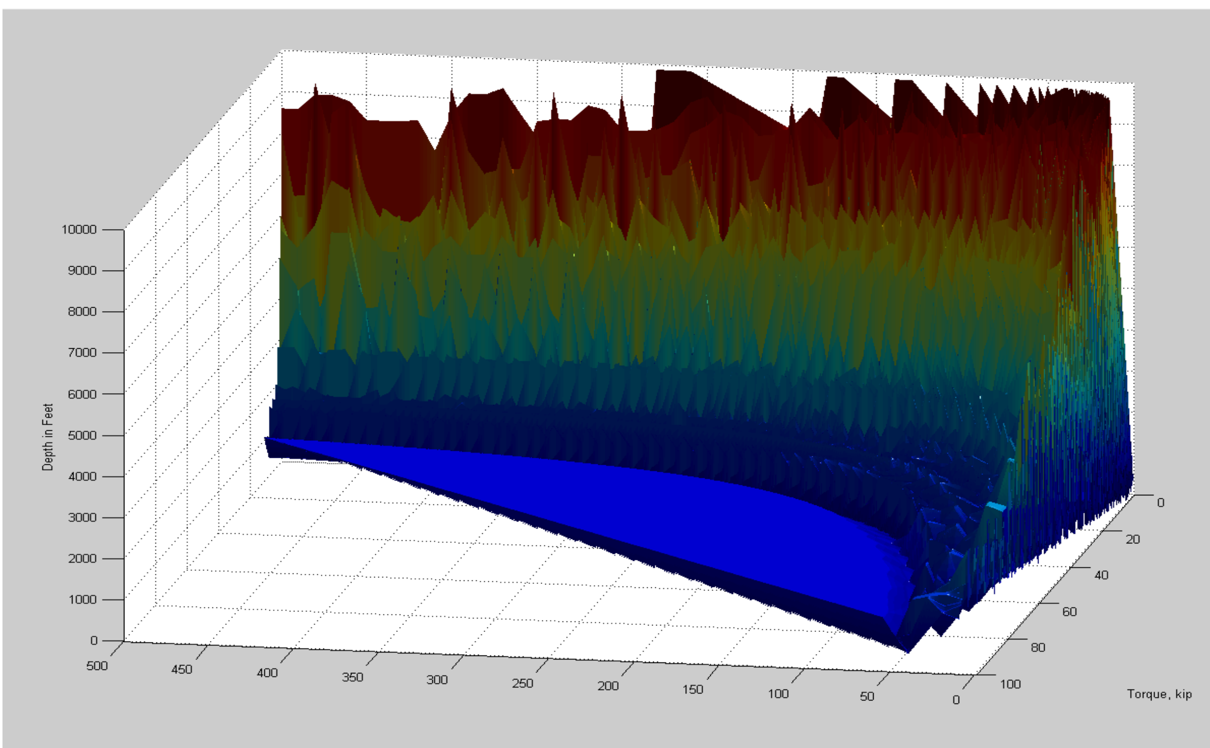

Figure 26: The lower depth values are highlighted to exemplify the greater range in RPM and Torque values necessary for efficient drilling (MSE/RS = 1 to 3). The values necessary for efficient drilling lie in the pool like region.

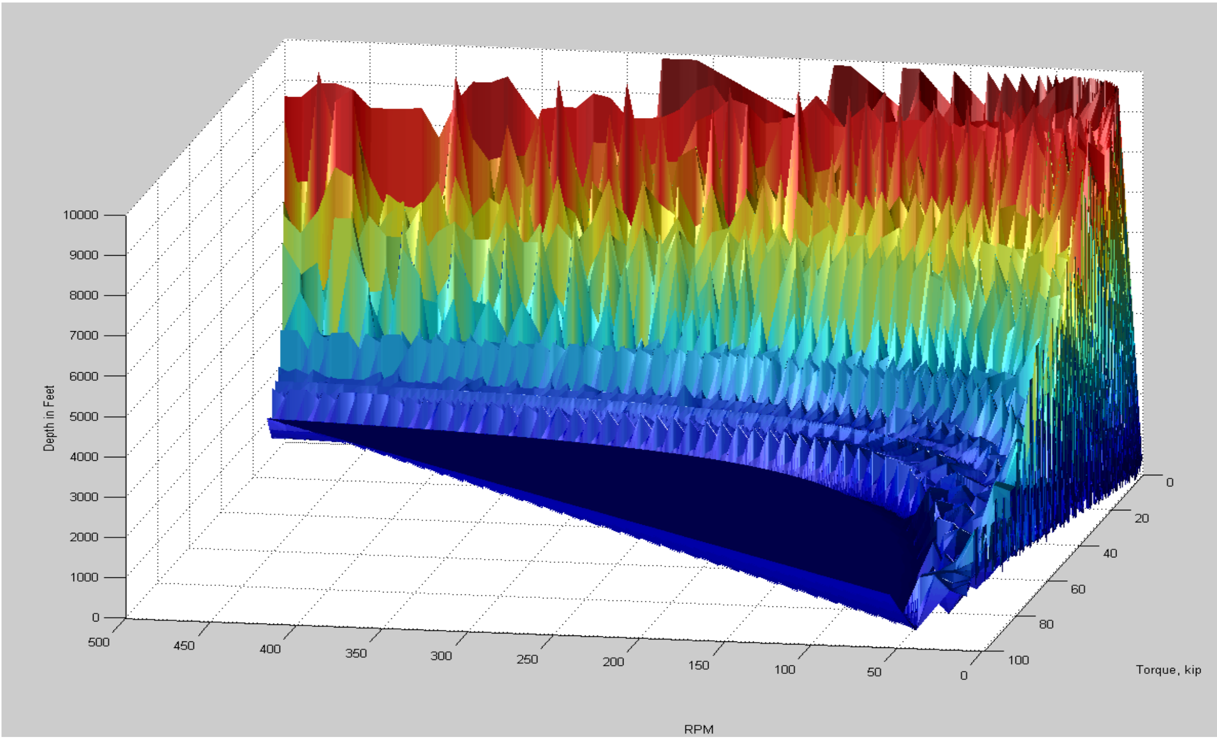

Figure 27: The higher depth values are highlighted to exemplify the lower range in RPM and Torque values necessary for efficient drilling (MSE/RS = 1 to 3). The values necessary to drill efficiently at higher depths lie in the 'cliff-like' region.

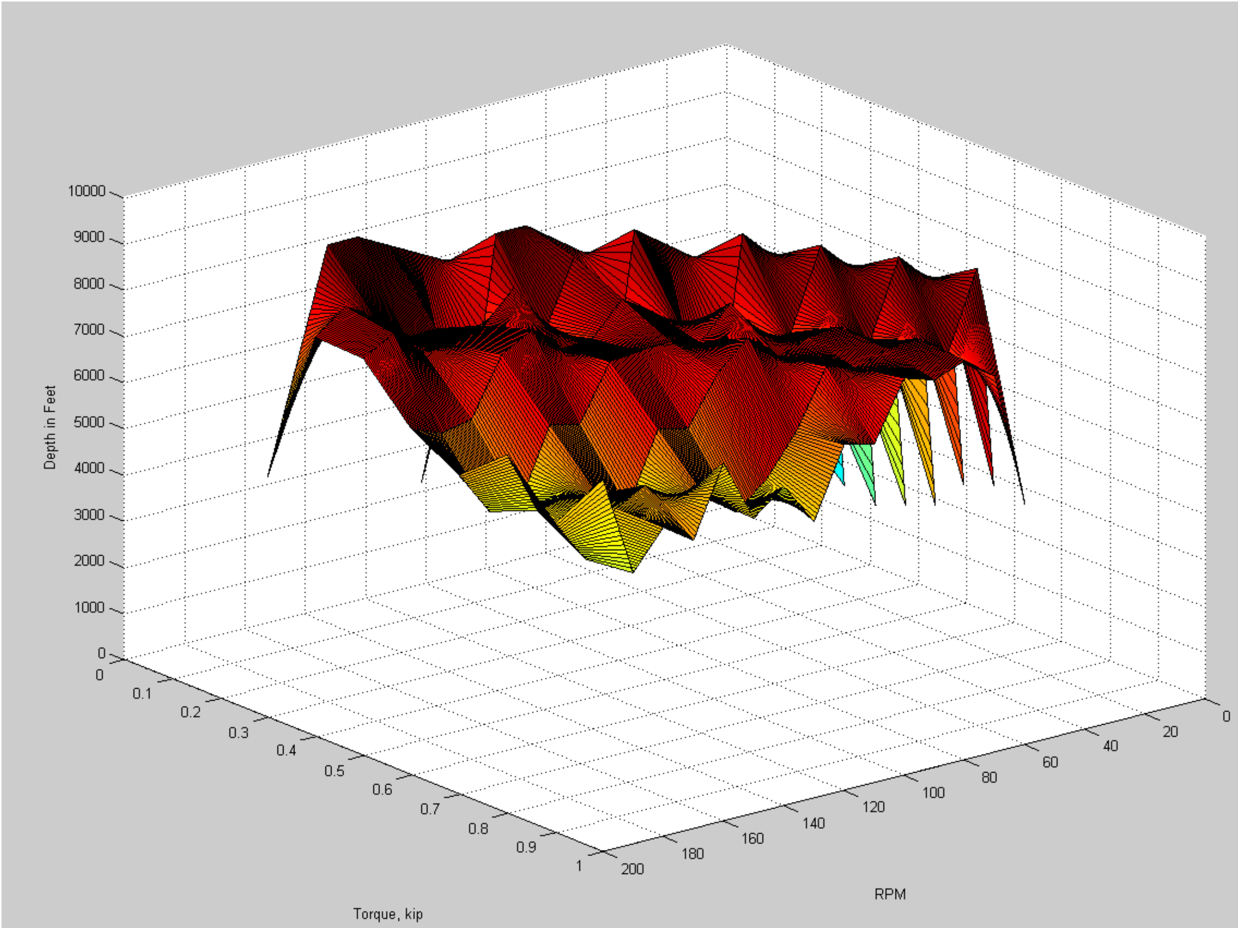

Figure 28: RPM and Torque ranges scaled back; the suspended model shape demonstrates a drilling rig that is challenged to effectively drill shallow formations; given the parameters provided.

Conclusions and Recommendations

The project confirmed the main problems plaguing the geothermal drilling sector, problems apparent in the comparative analysis of the 21 geothermal and 21 petroleum wells. The major factors influencing not only the large amounts of non-productive time, but causing even the programmed well operations to be slowed, were lost circulation, rig/equipment selection, cementing, rate of penetration, presence of a drilling program, and time management of the rig and crew. Through the identification of these issues, more can be done to mitigate and improve geothermal drilling and completion practices.

The research indicates opportunities to apply petroleum industry drilling practices to the geothermal industry, to reduce the current gap between the technical efficiencies of petroleum and geothermal drilling. Likewise, there are opportunities to apply lessons learned in the challenging physical environment of geothermal to petroleum drilling practices in more demanding environments. The integration of data from both fields can facilitate more efficient and cost effective drilling and completion processes.

One of the biggest advancements made from this research has been discovering how technical knowledge can be attained from the petroleum industry and applied to the geothermal industry and vice versa. Recent technological and management advances and practices within the drilling and completions sector which have been the work of many and have been a result of enhanced computing power; therefore, it can increase the efficiency of making usable hole in both industries. There are areas of improvement which can be realized within both industries; moreover, with integration of data from both industries, more efficient and cost effective drilling and completion processes can be achieved.

A key finding of this research is the lack of clean and easily interpretable data from geothermal wells; that is, legible, clear and complete reports to enable data analysis of potential improvements. Our research found many examples of hand-written and incomplete drilling reports. Deficient information allows uncertainty and inconsistencies in data interpretation, analysis and evaluation and limits the ability for continuous improvement. Data in an electronic and digitized format would have alleviated much of raw data misinterpretation as well as decrease time spent on modeling ROP efficiency. The acquisition of digital data would drastically reduce time spent analyzing ROP efficiency, potentially leading to better, less expensive, and useful modeling techniques.

The results of the research have provided for a better understanding of geothermal industry's practices and of the challenges incurred in constructing a usable geothermal well. The impending challenges recognized continuously by the research team are:

- Lost circulation mitigation
- Proper rig and equipment selection
- Proper cementing practices
- Mechanical Specific Energy (MSE)
- Technical Drilling Program
- Time Management Evaluation

During processing the data received it was discovered that the quantitative and qualitative content of the data varied substantially. It has been noted throughout the various sections of the report that the data was either missing or incomplete. Thus, it is imperative that consistent, thorough, and complete data be obtained for future analysis to ensure an improved thesis on the ends that the research team is working towards. A recommendation would be to seek out arrangements which can be made with willing participants to establish a model format to provide for consistent data. Furthermore, more specific sub-divisions of the drilling and completions process should be included within the scope of the potential project to allow for a complete overview.

The findings of this research are promising in identifying paths to improve geothermal drilling practices. Lost circulation mitigation, good rig and equipment selection, new cementing methodologies, mechanical specific energy analysis for increased rates of penetration, employment of a thorough drilling program, and better time management evaluation are key areas of further investigation in the second year of this project to improve efficiency, risk reduction, time and capital allocation and to reduce the cost of geothermal drilling.

In short, the findings of the research team are such that many challenges face the geothermal industry such as the competition for resources, technological knowledge, human expertise, and adequate practices to overcome the geological lithology which is an inherent challenge in creating geothermal wells. Without doubt, this research has merely scratched the surface of the realities which must be addressed to realize our ends for obtaining this invaluable renewable energy.

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- Neil Snyder
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- John Hansen
- Sonja Houston

Operators

- There were many who supported this project with data. As part of that sharing, we are under a non-disclosure agreement with those various operators. We acknowledge their support and thank them anonymously.

Interviewees

- Douglas Blankenship, Manager, Geothermal Research, Sandia National Laboratories
- Paul Brophy, President and Principal Geologist, EGS, Inc.
- Louis Capuano, Jr., CEO Capuano Engineering Company
- Paul Graham, Drilling Engineer, Calpine
- Roy Long, Ultra-Deepwater Technology Manager, National Energy Technology Laboratory Houston
- Chuck Mallory, Director of Drilling Technology Rocky Mountains, Noble Energy Company
- Stephen Pye, Consulting Drilling Engineer.
- Bill Rickard, Geothermal Resource Group

- Robert Sencenbaugh, Drilling Engineering Manager, Sklar Exploration Company
- Nick Spence, Drilling Engineering Manager, Anadarko Petroleum Corporation
- Tommy Thompson, Director- Engineering and Technology, Anadarko Petroleum Corporation
- Virgil Welch, Oil and Gas and Geothermal Drilling Consultant

Appendix

Procedure – IDS

IDS Datanet software is a breakthrough effort by Independent Data Services. It has been around for 15 years with primary uses being to be able to jot down working data for drilling and workover operations for any types of pay, such as oil and gas, geothermal, gas, oil, helium and water.

The software has been designed in a user-friendly format. At the beginning, it is arduous to figure out the right tabs to begin the plotting work. This is because the interface looks complicated with ambiguous tabs. But, it becomes very handy and easy once constant practice went on. To begin with, there are a total of 7 tabs in the software. These are available upon login. Below those tabs, there are drop down mini-menus, namely 'Well/Ops" and "Datum", in order to pick the well that is being worked on and the associated datum respectively. Below those small menus, comes the main working space for the software. Let's begin exploring this software by peeking into each tabs and analyze its' functionalities in detail.

The first tab is called "Main". The first function that is listed under this tab is the data population matrix data. Data population matrix reveals the entire platform and modules for an important tab "Drillnet", which will be discussed later in this write-up. Intersecting elements in this red-green matrix can be clicked in order to access detailed per-day activities of respective wells. The second function listed down under this 'Main" tab is the Operation Information Center Data. This is pretty useful tab in which it shows us the summary well's operations and rig data. The following "Well Explorer" button pops up a spreadsheet like list that opens up on data regarding the operations, well names and its' one liner daily information.

The second tab is called "Well Data". Well Data has three main functions under it, namely Well, Wellbore and Operation. This is the actual place to begin the work. New well names are added in the "Well' page by writing down the well name and the country and state information, followed by indicating its' location (offshore/onshore), pay type (geothermal/oil and gas/oil/helium/gas/water) and ground level in feet. After setting the GMT Offset value and writing down information on the location detail, it's time to move on the next function - Wellbore. Under this function, we could name the well, its' wellbore's name, purpose and type. Wellbore purposes include appraisal, delineation, development, exploration, injection, production and other. Wellbore type on the other hand includes pilot, initial, sidetrack, slot recovery, mechanical sidetrack and multi-lateral log. Next up is the "Operation", in which we are allowed to state the operation and completion type, mention the operating company (in this research case, it is our school, Colorado School of Mines) and operation rig. Apart from that, start and spud date & time could be selected from a list of drop down menu.

The third tab under concern is the "Rig Data". This tab could be used to take a look at the list of rigs and used for the wells in this IDS Data Software. Rig name, drilling company, owner, rig type and max depth can be overwritten. The most important tab of all would be the Drillnet. The first function under this tab is called "Daily". Here, we could write the day, the number of the day, rig used and its manager, days spent on well, days since spud, current hole size, midnight depth, last casing size, last casing shoe

(MD/TVD) as part of the data as of report time. Furthermore, we could write down the summaries and plans for that particular day, which includes the status at midnight, 24 hour summary, status at 0600 hours and the day plan. In this research, we did not tabulate data into these summaries because it wouldn't mean much as no results could be outputted using these. Instead, we mainly used the next function under this tab, which is known as "Activity". Composed of five rows (start time, end time, amount of hours spent between this interval, description of activity, codes and depth), the activity function is the deciding function to output vital results to be studied and analyze at the end part of this data tabulation work.

Most of the geothermal wells we've worked on for this research work had daily drilling reports starting its' operation at 00.00 hours and ending it at the 24th hour, except for a few. Therefore, after selecting the respective day at the previous "Daily" tab, the next step would be to hop into this activity tab and tabulating per day information for each of the operations in that particular well. After selecting the start and end time based on the daily drilling report, the software calculates the total hours spent between those two intervals. Next up is the description. Our task as data tabulators was to understand the activity done before writing it down. This is to avoid unnecessary confusions regarding the type, function and purposes of an activity that may arise in the later part of the data tabulation process. In order to facilitate our work and make it fast, efficient and smooth, we've tried reading and understanding each activities and then tabulate it in the "description" text box. Following that, we had to deal with the codes column. Under this column, there are three fill up boxes namely Class, Phase and Operations. For this research purposes, we've used two out of the four operations provided, which are Programmed Event (P) and Trouble – During Program (TP). Phase describes the stage of the operation a well is having at that instantaneous point of time. The list of phases available would be casing (with different inner diameters), diverter/wellhead/BOP, drill hole section (with various inner diameters), drive conductors (with various inner diameters), fishing /milling/cutting/perforating, formation evaluation coring, formation evaluate logging, liners (with different inner diameters), pilot hole, plug and abandon, plug back/cement plug, pre-spud operations, side track, suspention and well control. Next up is the operations type that varies according to the type of phase selected. To provide an example in order to give a clearer picture on how this "Codes" part works, let's say the type of class selected for an activity in the description is Programmed Event (P). The associated phase could be anything, but let's say we are selecting "Drill Hole Section" to represent a drilling activity during that period of time. Under that phase, the list of operation available for selection would be circulate to condition mud, cure losses, directional survey, download LWD, drill ahead rotary, drill ahead RSS, drill ahead sliding, drill off test/fingerprint, drill ahead hole opening/under reaming, FIT/LOT, FIT/LOT circulate condition mud, flow check, L/D BHA, L/D Retrievable Packer, M/U BHA, M/U MWD/LWD, Pre-Job Safety Meeting (PJSM), POOH in casing, POOH in Casing Back Reaming, POOH in Casing Pumping, POOH OH, POOH back reaming, POOH retrievable packer, POOH running tool, pump pill, repeat section log (RSL), rig maintenance, RIH in casing, RIH in OH, RIH retrievable packer, RIH running tool, RIH wash ream, RU to run directional survey, set and test retrievable packer, shallow test MWD/LWD, skid rig, slip/slip and cut block line, slow circulating rates, SPUD and drill ahead hole opening/under reaming, SPUD and drill ahead rotary, SPUD and drill ahead RSS, SPUD and drill ahead sliding, squeeze, wiper trip/check POOH back reaming, wiper trip/ check trip POOH pumping, wiper trip/ check trip RIH, wiper trip/ check trip RIH was ream and work/jar drill string to free stuck pipe. Let's say if the activity part stated that the particular operation faced lost circulation problem, then the class would be changed from Programmed Event (P) to Trouble – During Program and an additional text box appears with the name Root Cause (RC). Under this RC drop down list, we would be able to select respective problem instigators such as lost circulation, stuck pipe and accident/injury and the like. This "Codes" part of the data tabulation is vital to produce meaningful and correct data at the end of the process, which is precisely the reason why we need to spend time understanding the activity description first before writing all those into the text box. Sometimes, the job becomes easy with the report having activity acronyms that match the ones in the phases such as SUSP for suspention, SITR for side track, WECO for well control and FELO for formation evaluate logging. Otherwise, it takes time to identify the right activity in the phase.

Below the "Daily Activity" page, the number of days is listed. This makes the task easy when it comes to navigating across days of activity faster. The "copy/paste from yesterday" function found at the top of the page cut downs the time required to spend on tabulating activities into the software. It could help in copying activity details from the previous day and paste it in the current day panel. The next most important tab would be the VisNet Basic. This would the hub for all the results storage based on the previously completed data tabulation. The most important sub-function under this tab is the double drilling dashboard. One could be used to display current well's information and the other is particularly useful to compare data from multiple wells. Under this function, ten types of final result that lays out one or many well's particulars in excruciatingly details could be obtained. The first is the planned vs actual plot, which is basically the drilling time curve. With depth in feet at the y-axis and days (d) at the x-axis, we could observe the well(s) performance and ROP over time. The borehole schematics weren't used much, similar to the vertical section and plan view. The next vital piece of information would be the root cause breakdown. It lists down the types of troubles encountered during the drilling/workover operations in the well(s). An example of a root cause breakdown window (one that belongs to well Geo 12) is shown in Table 1.

Table 2: An Example of a Root Cause Breakdown Table

Root Cause Breakdown (Current)

Root Cause Code Breakdown

Root Cause Code	Total Duration (h)
Stuck Pipe (DSP)	8.50
WOT (Wait on tools)	10.50
WOR (Wait on repairs)	11.00
Labour industrial dispute (DLD)	16.00
Other rig contractor equipment, personnel or procedures (DRO)	26.00
WOC (Wait on cement)	26.50
Mechanical Borehole (DHC)	36.50
WLD (Wait on daylight)	43.00
Lost Circulation (DLC)	497.55
Total	675.55

As observed, the table lists down the troubles faced by a well and by using the details of information provided by the above table, one could identify the main problem which is bothering the well(s). Next up, phase codes breakdown displays the types of phases the well(s) went through, throughout its operational time. An example of a phase code breakdown (one that belongs to well Geo 12) is shown in Figure 30:

The other two important final result charts are the drill down and class code breakdown charts, as shown in Figure 30 and Figure 31.

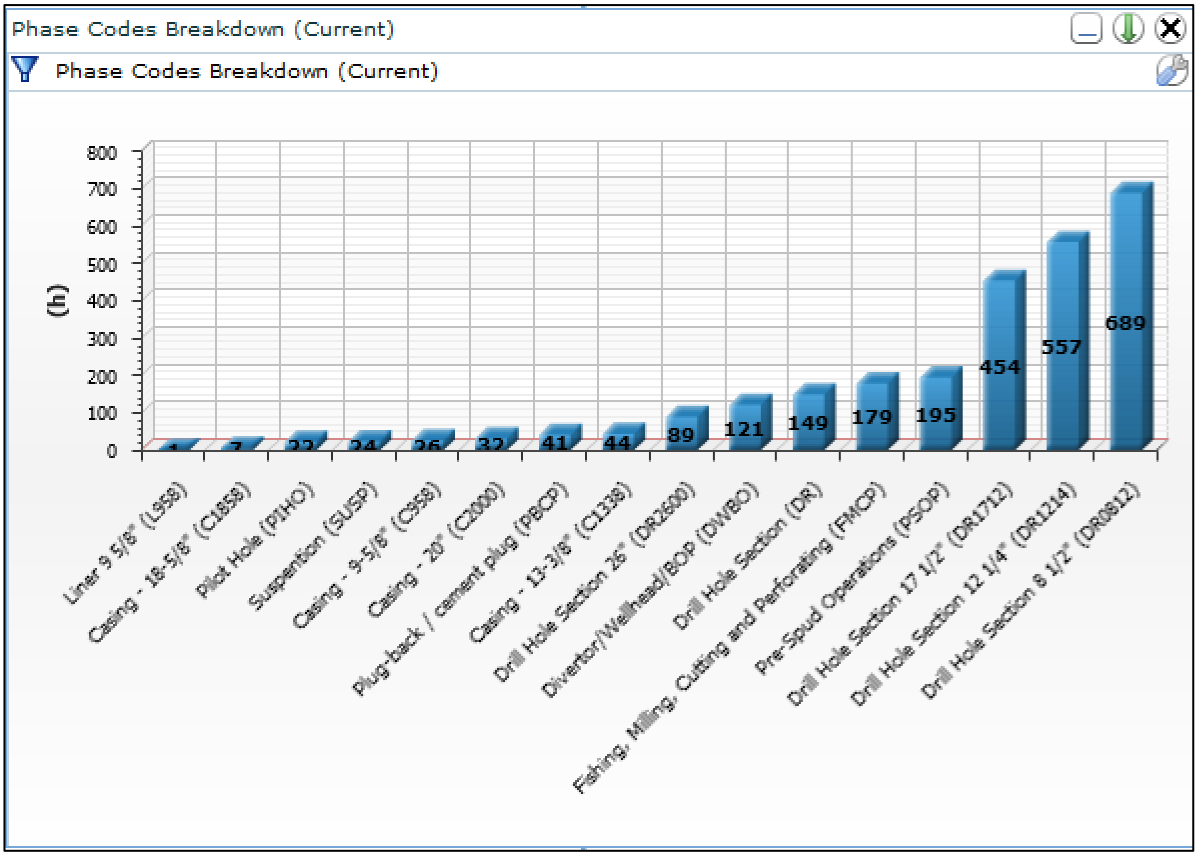

Figure 29: An Example of a Phase Code Breakdown Chart

As can be seen, the class code breakdown and drill down chart are basically the similar data presented in different format. The orange part of the data represents the non-productive time (NPT) spent on a well, whereas the green portion represents the productive time (PT) spent on a well. A clear display as such gives us a clear picture on the well(s) performance as a whole.

Finally, there are the days versus depth chart shown in figure . This shows how the operation performed over time relative to depth. When the line goes up, that means the loss of hole. The flat areas are where no progress towards penetration was made. This could be productive time such as logging or running casing or it could be non-productive time such as lost circulation events, rig breakdown, etc.

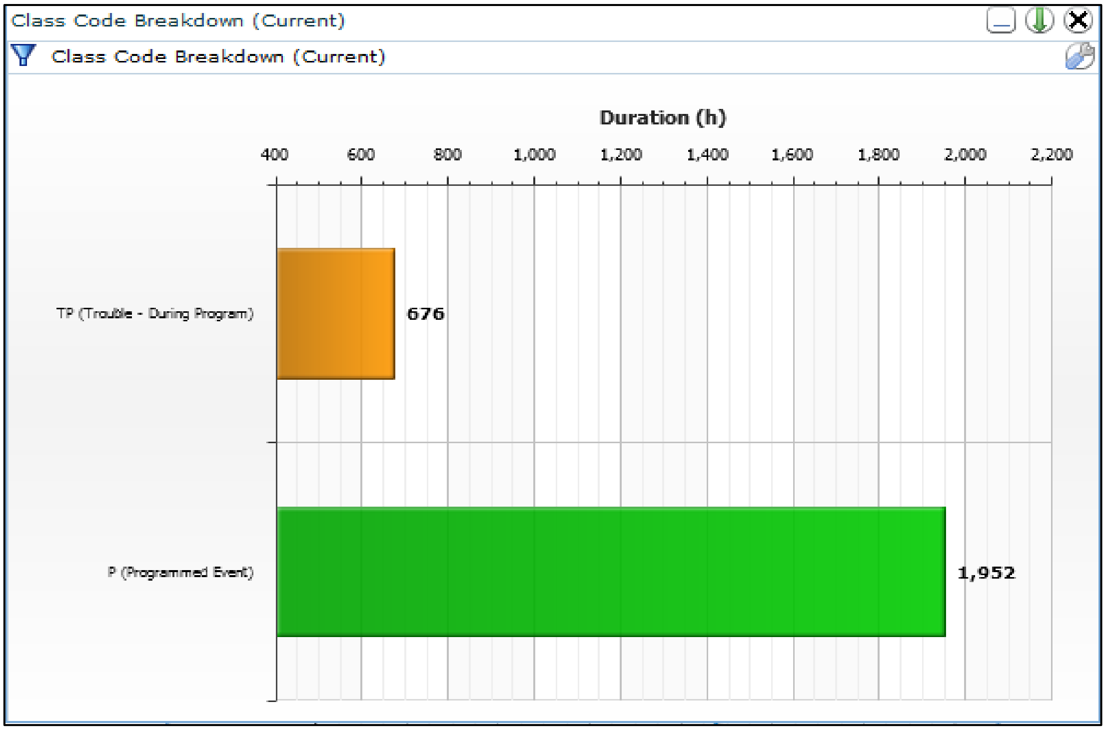

Figure 30: An Example of a Class Code Breakdown Chart

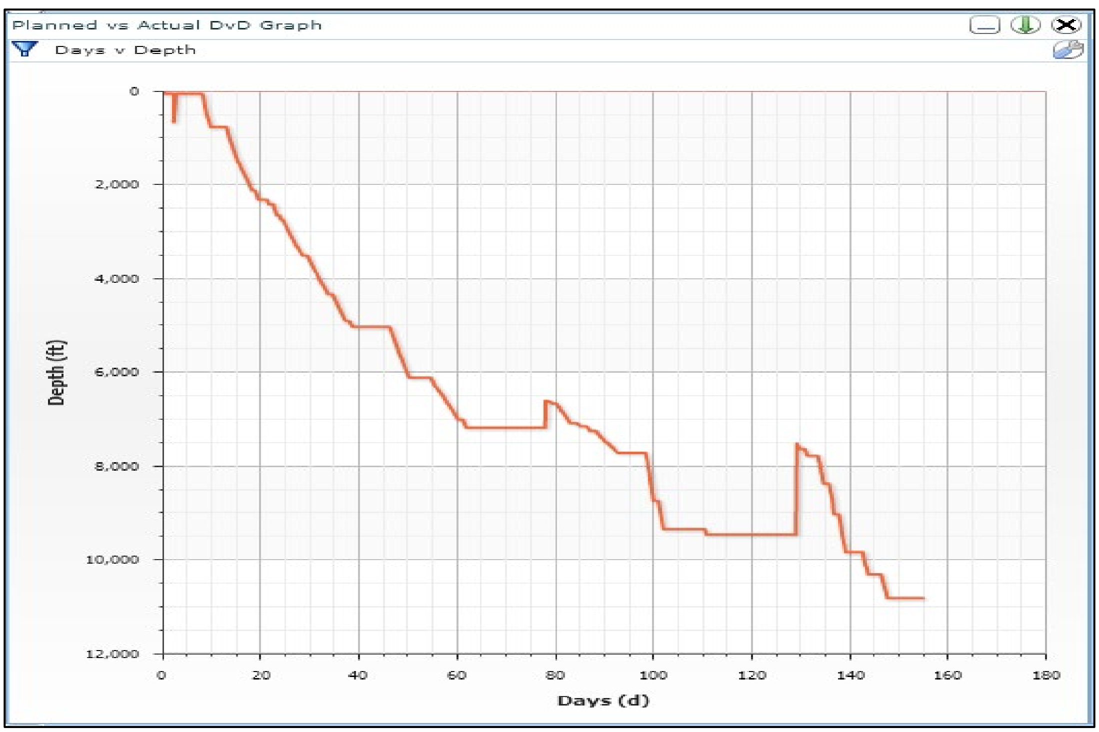

Figure 31: Geo Well #1: Days vs. Depth Drilled

Data Output and Analysis for All Wells

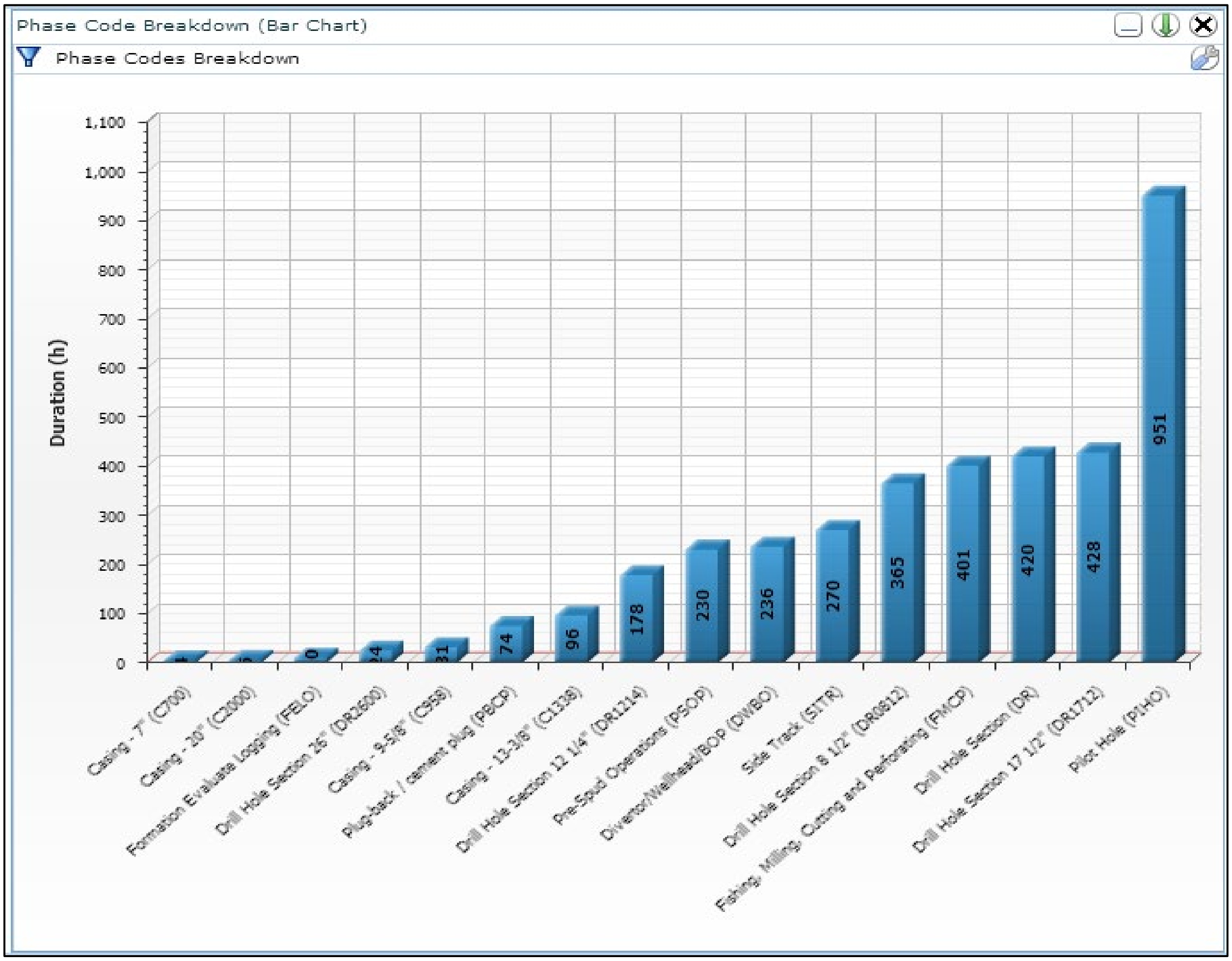

Figure 32: Geo Well #1; Phase Code Breakdown

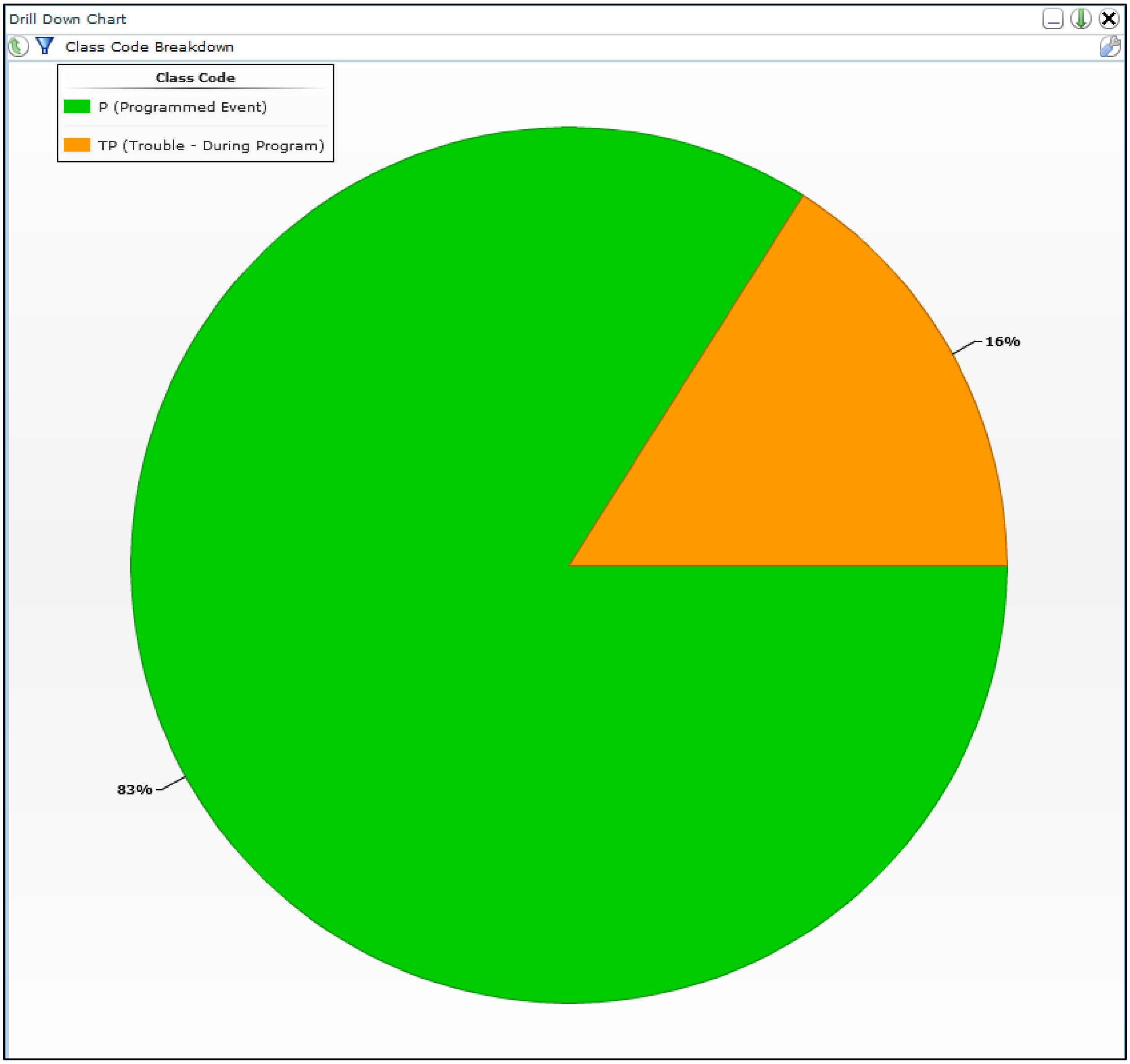

Figure 33: Geo Well #1; Percentage of Class Code Breakdowns

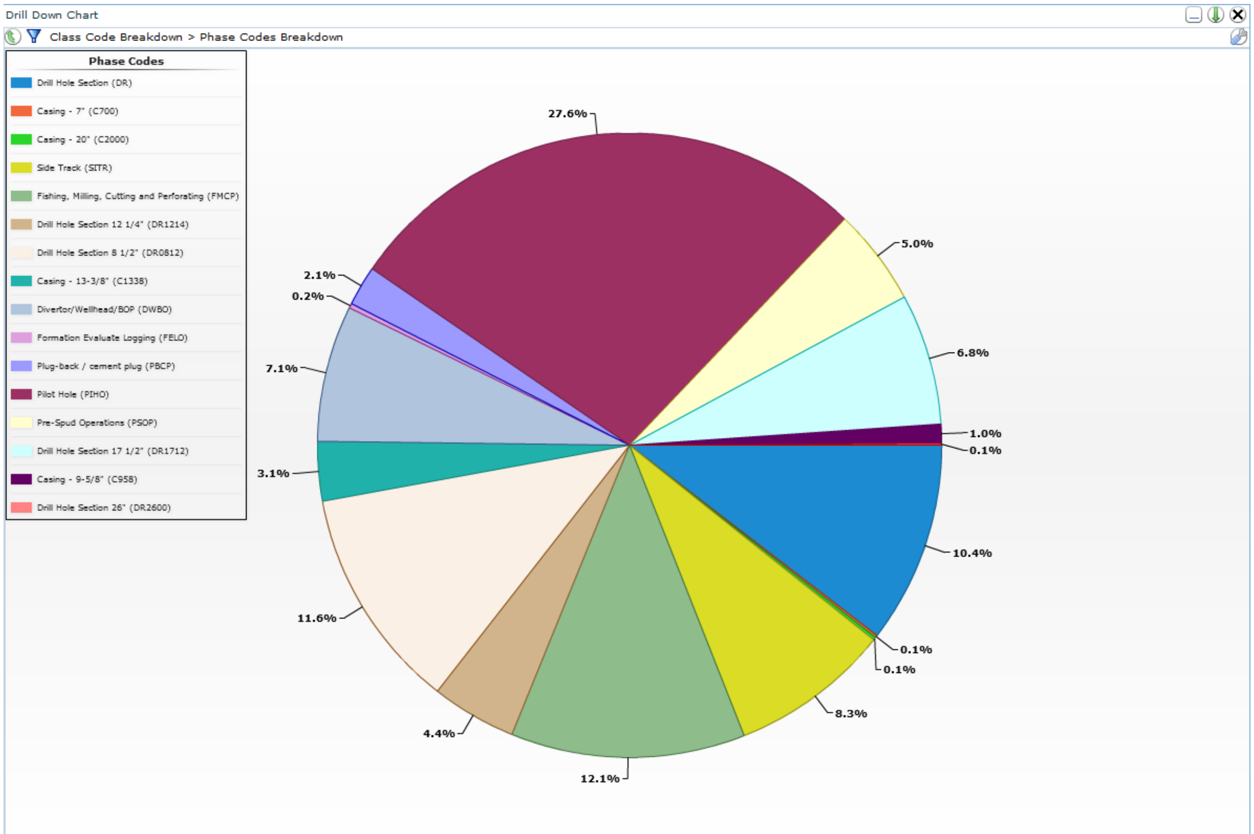

Figure 34: Geo Well #2; Percentage of Programmed Phase Code Breakdowns

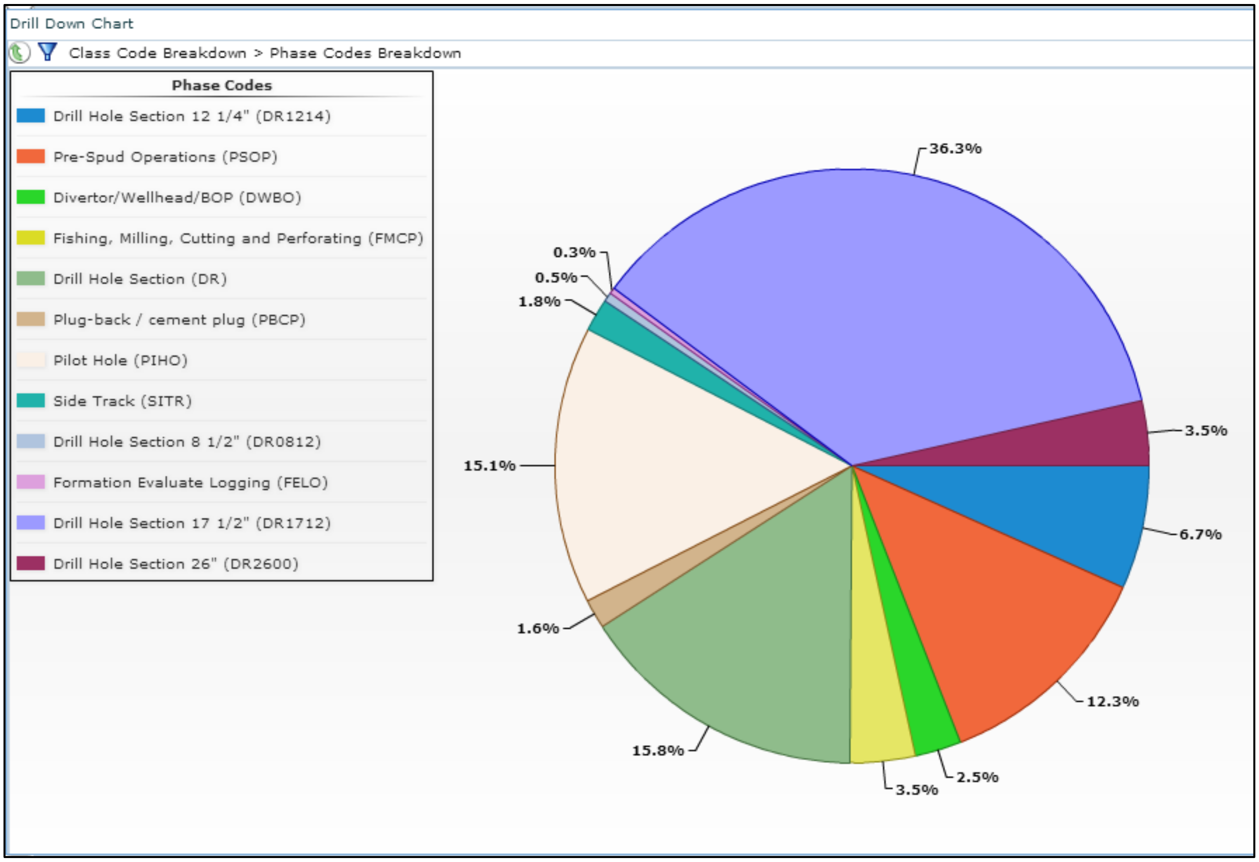

Figure 35: Geo Well #1; Percentage of Trouble during Programmed Phase Code Breakdowns

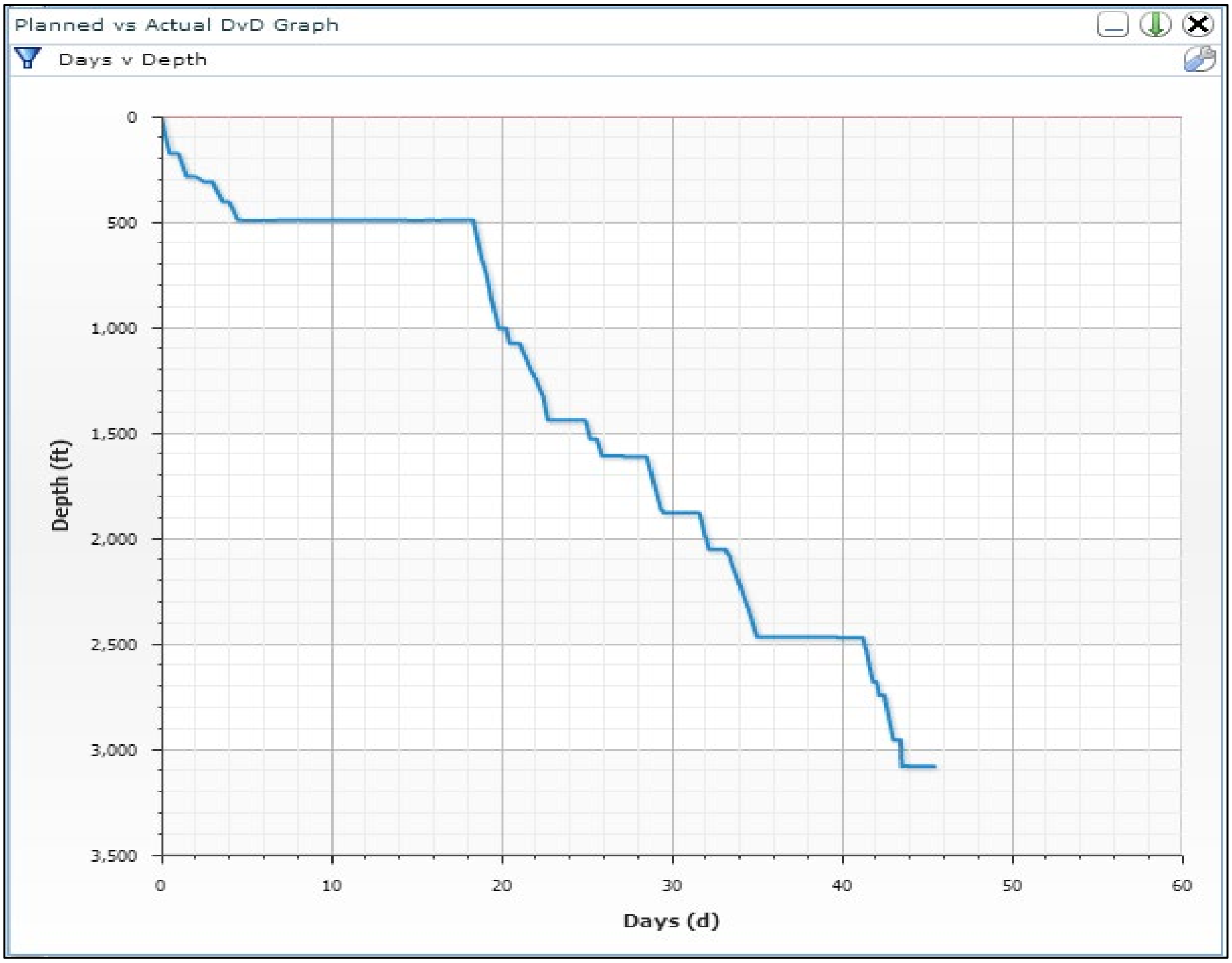

Figure 36: Geo Well #2; Days vs. Drilled Depth

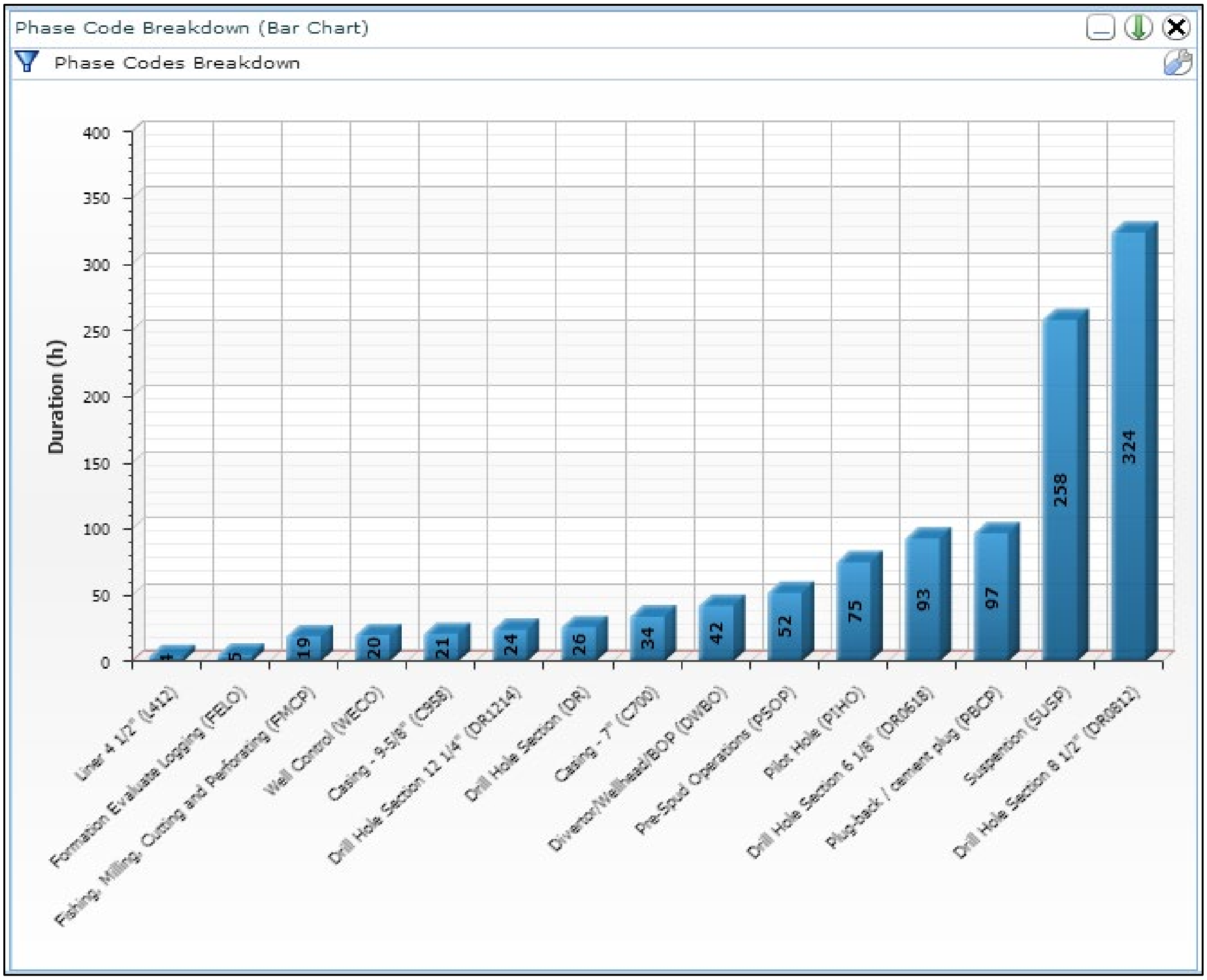

Figure 37: Geo Well #2; Phase Code Breakdown

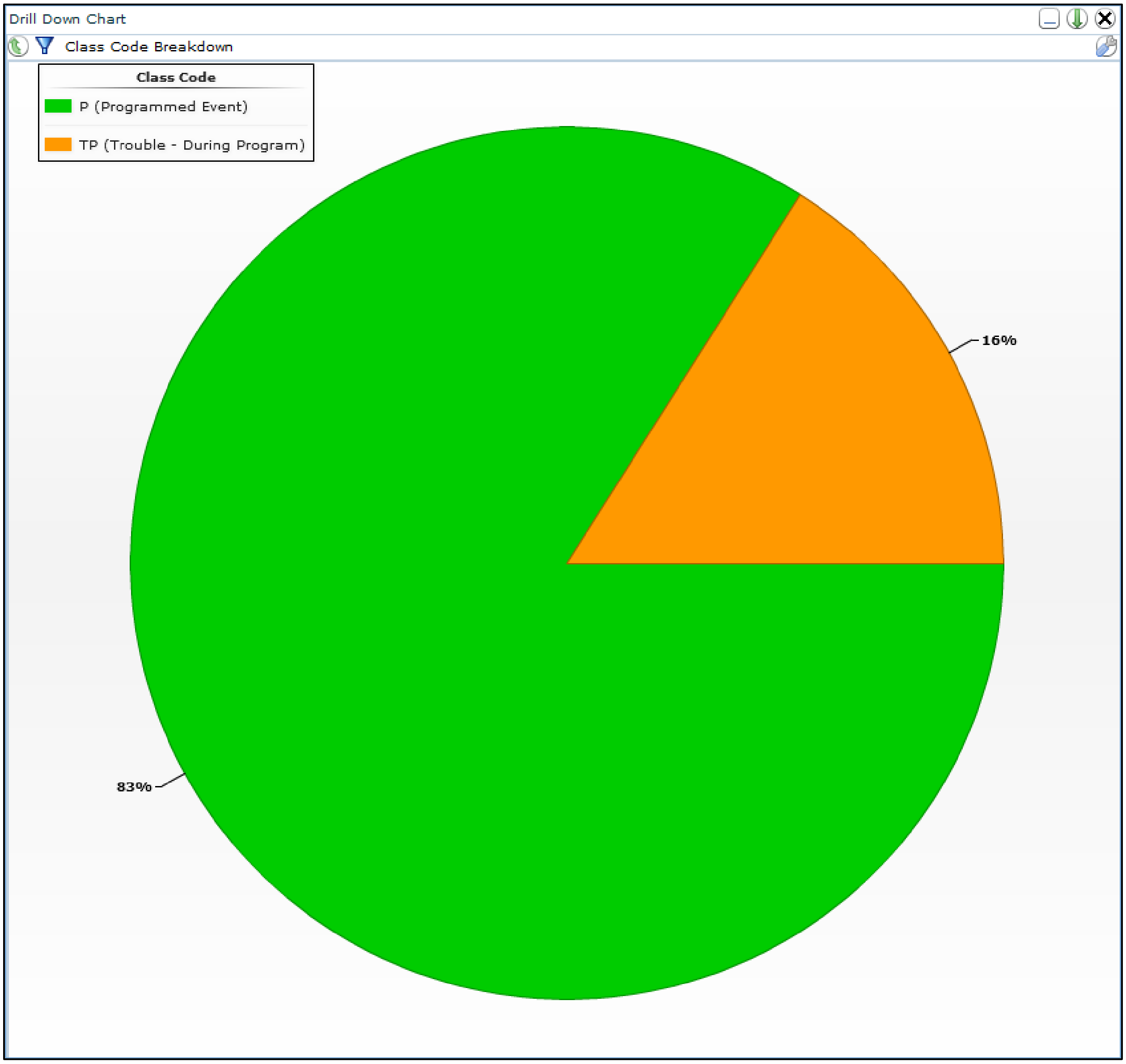

Figure 38: Geo Well #2; Percentage of Class Code Breakdown

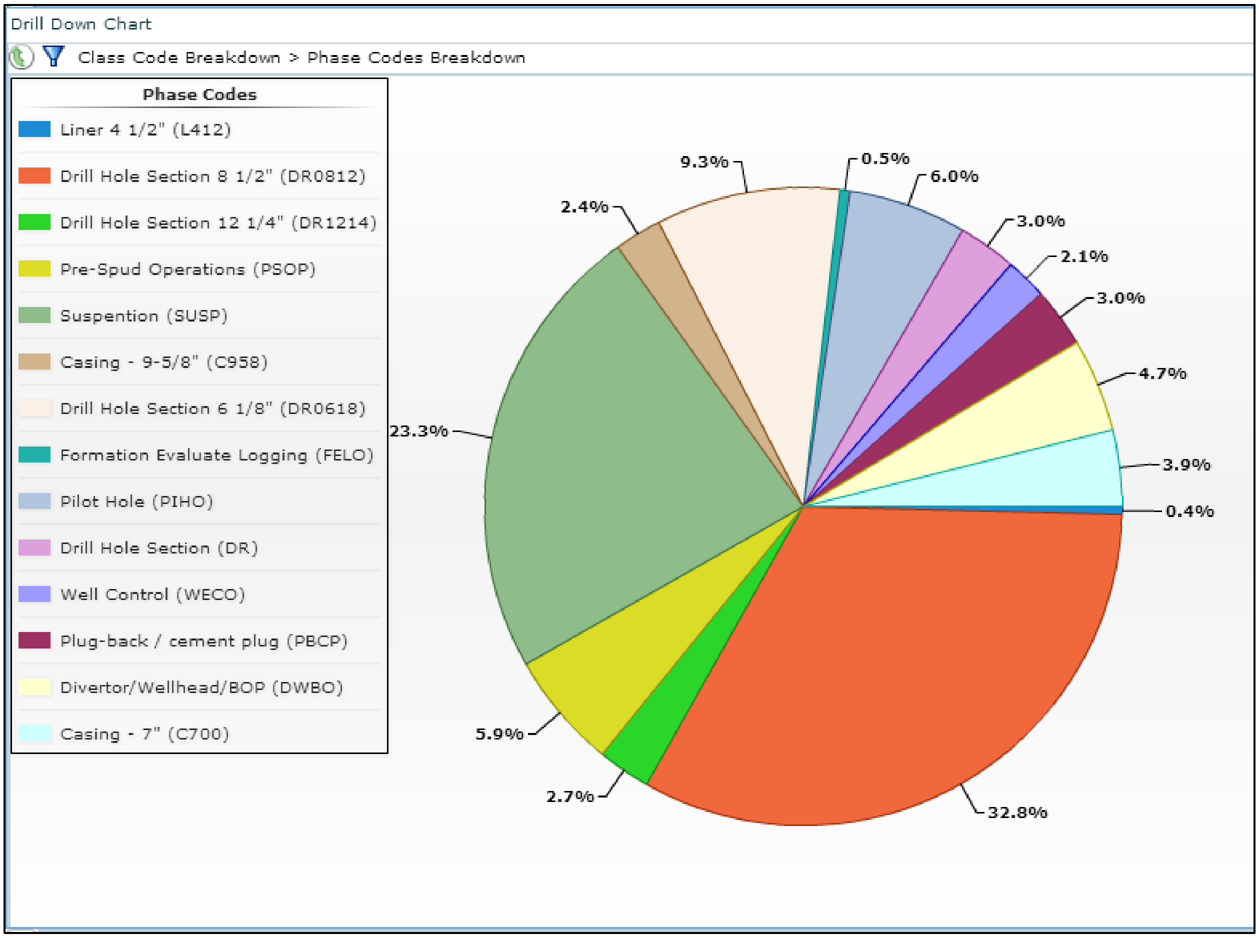

Figure 39: Geo Well #2; Percentage of Programmed Phase Code Breakdowns

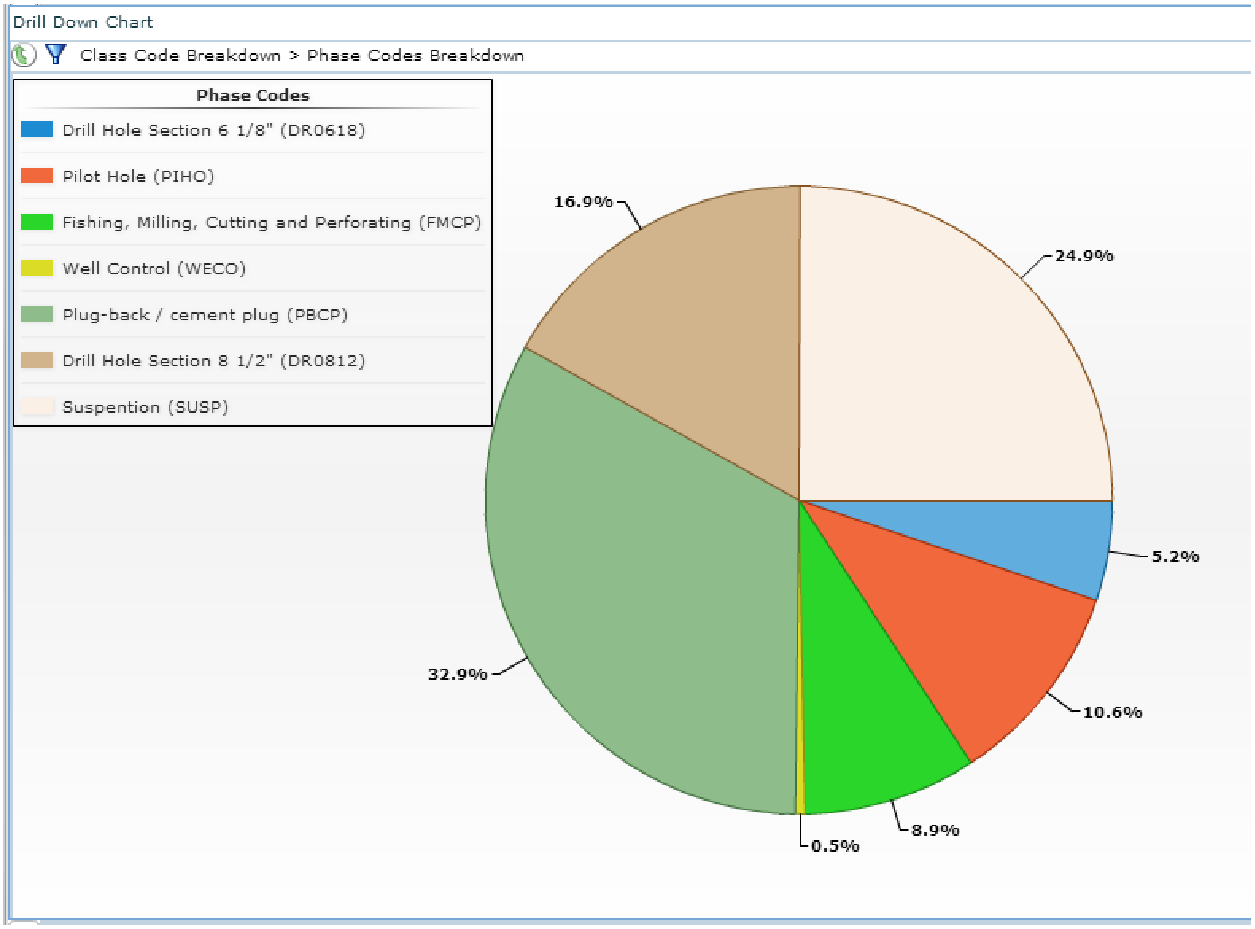

Figure 40: Geo Well #2; Percentage of Trouble during Programmed Phase Code Breakdowns

Note:

Geo 3, 4, 5: Incomplete Data

No Figures Available

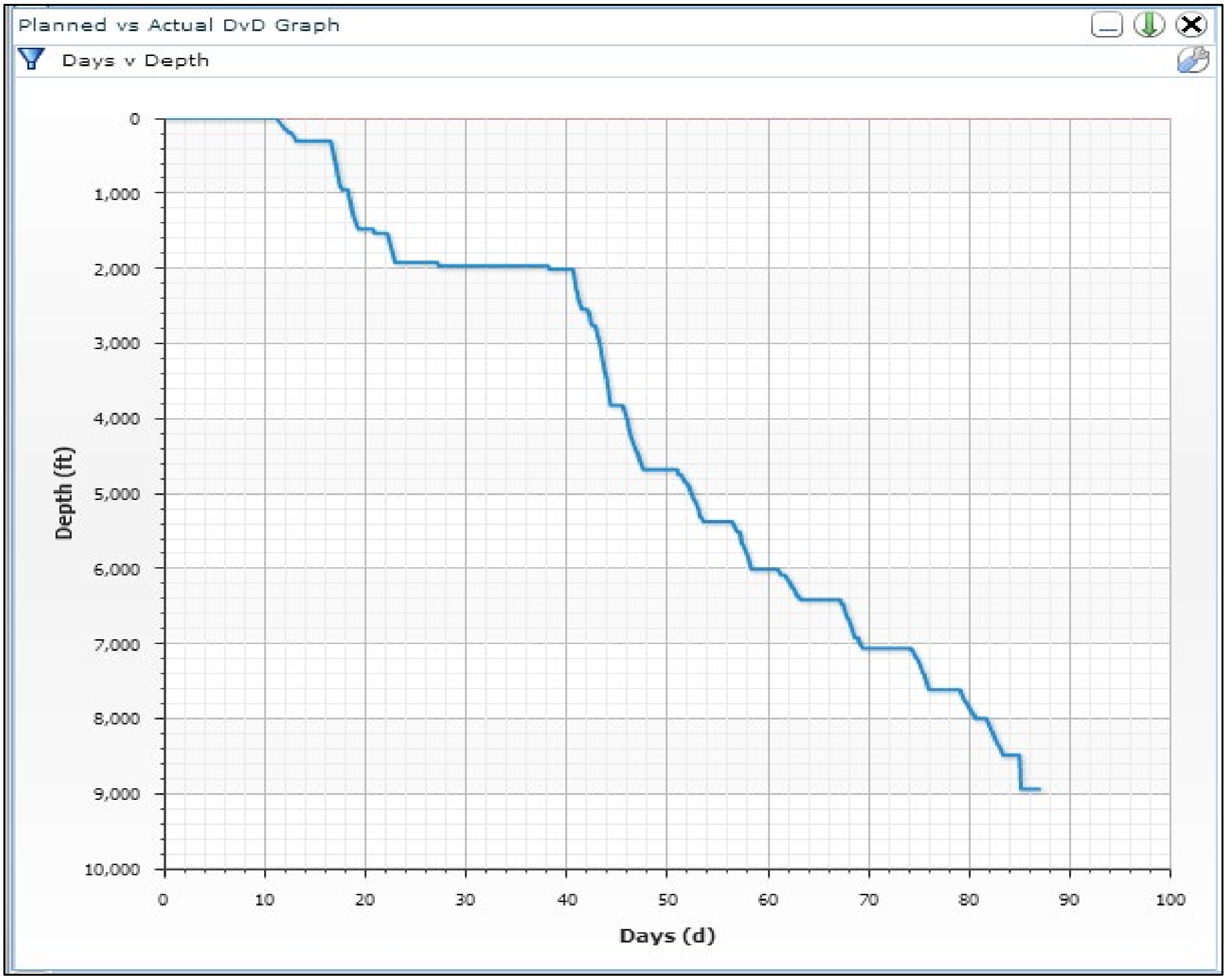

Figure 41: Geo Well #6; Days vs. Depth Drilled

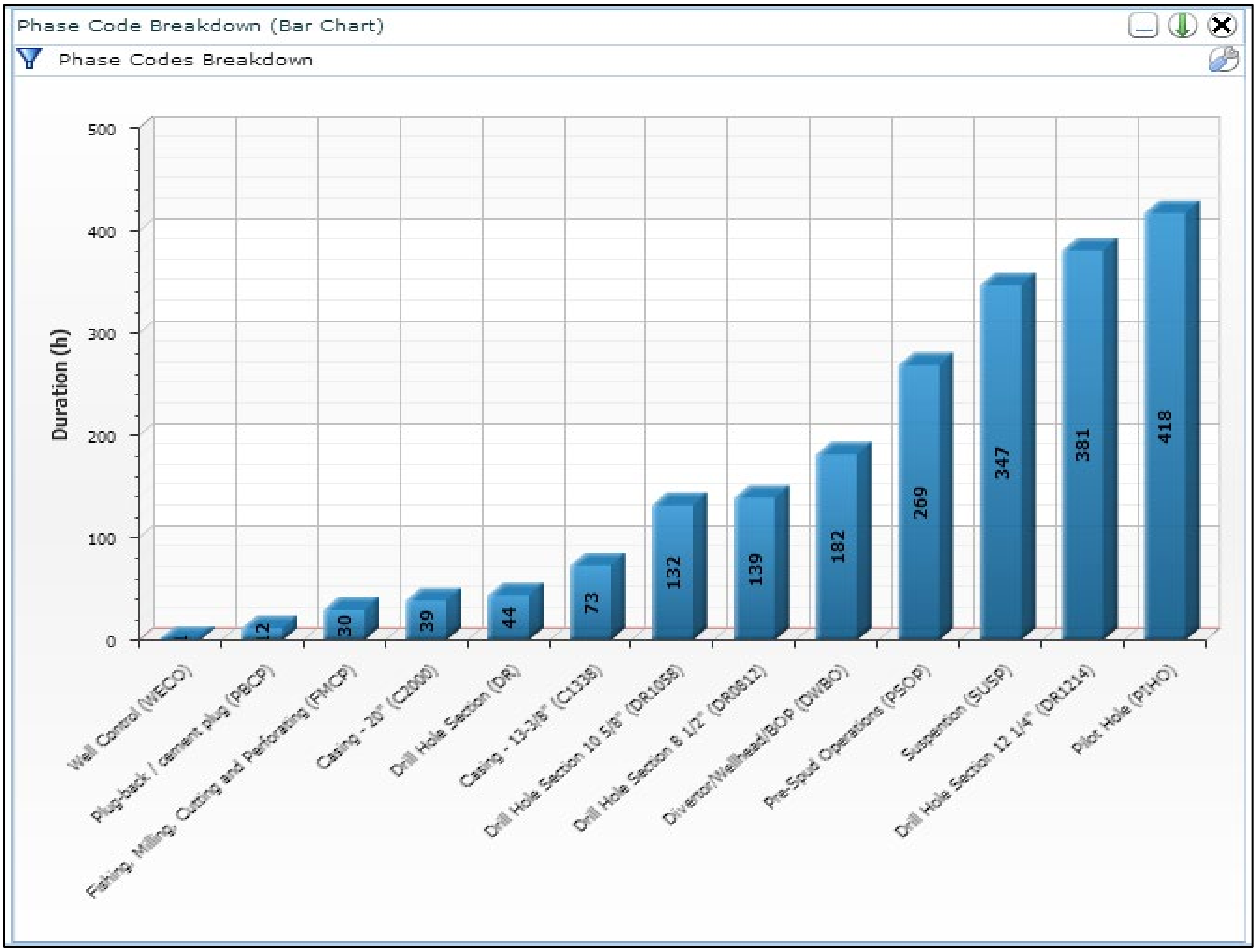

Figure 42: Geo Well #6; Phase Code Breakdown

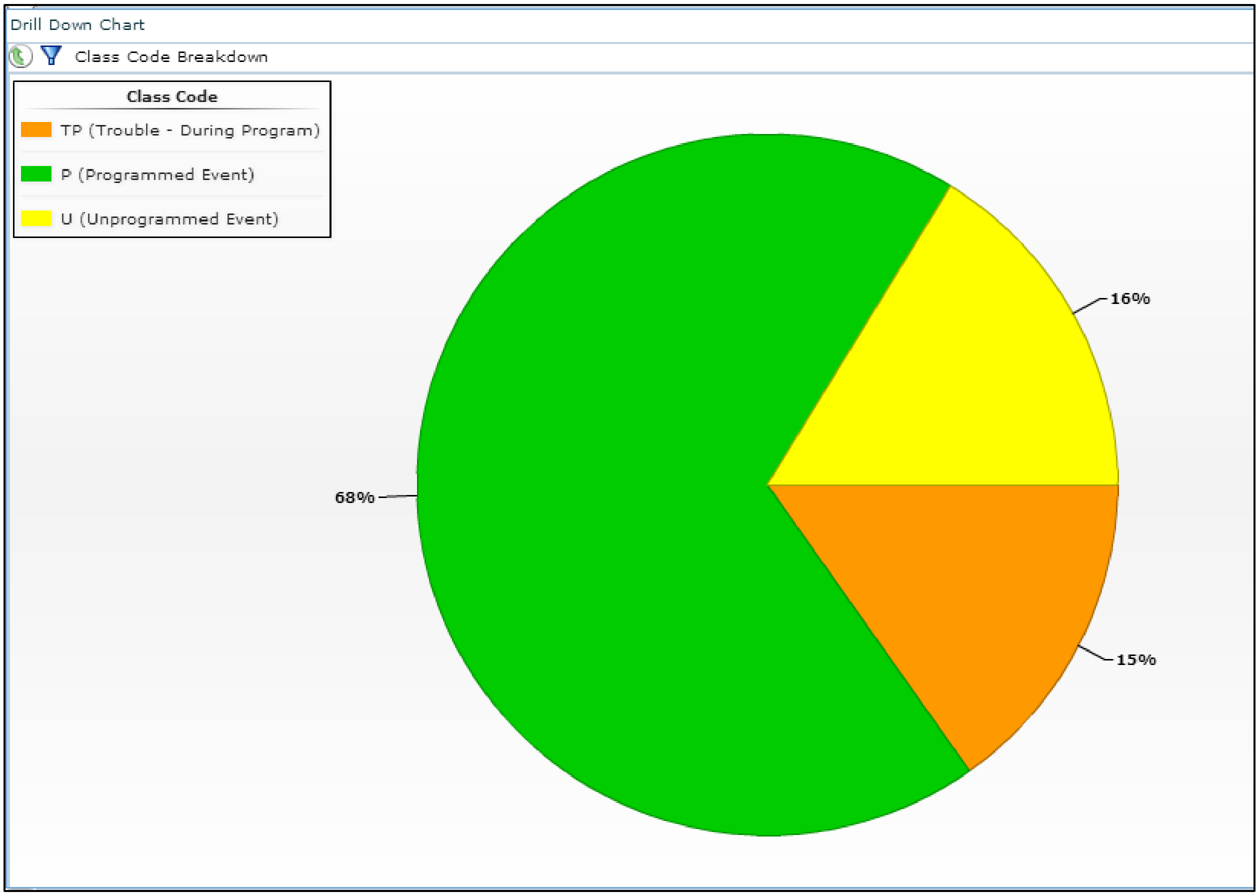

Figure 43: Geo Well #6; Percentage of Class Code Breakdown

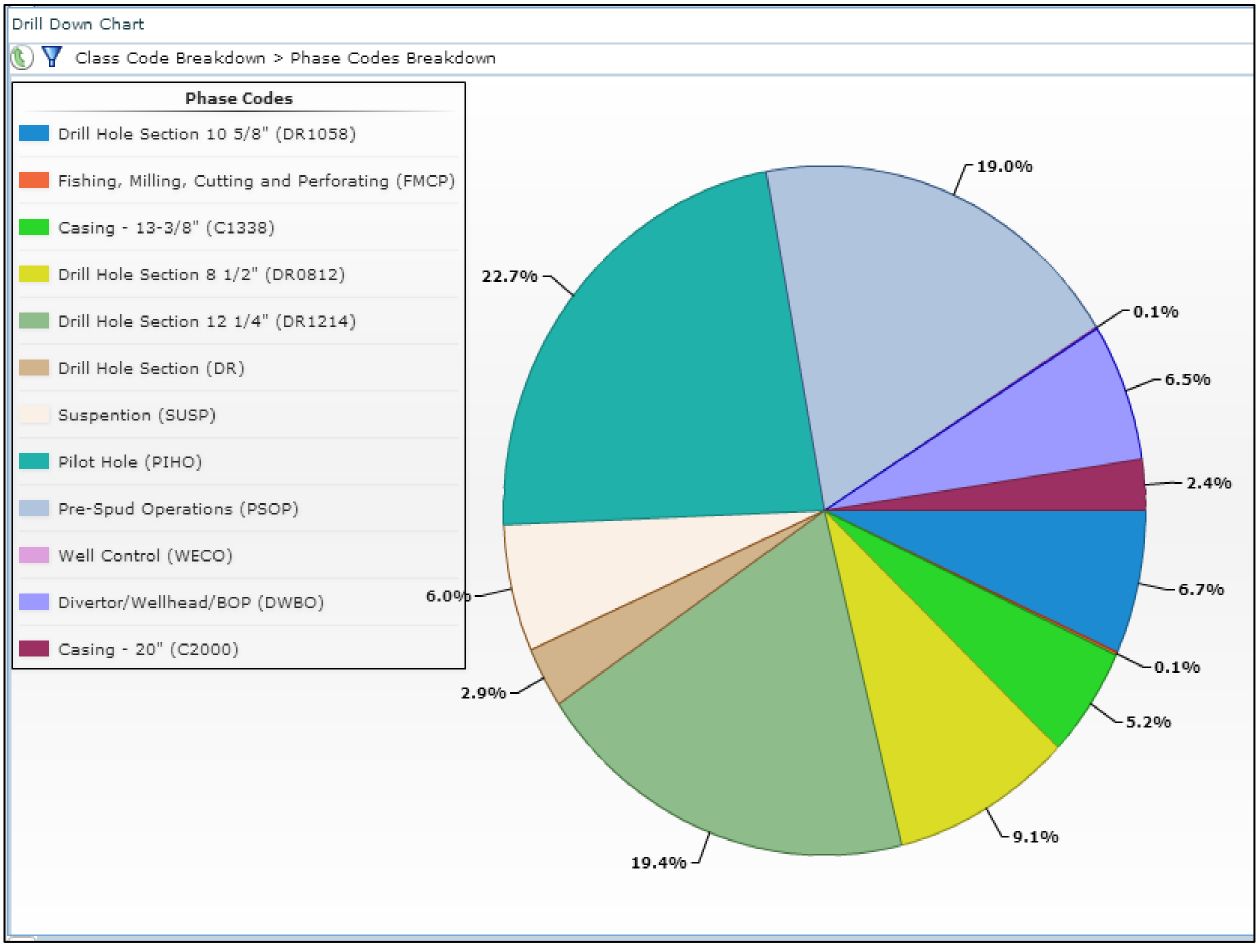

Figure 44: Geo Well #6; Percentage of Programmed Phase Code Breakdown

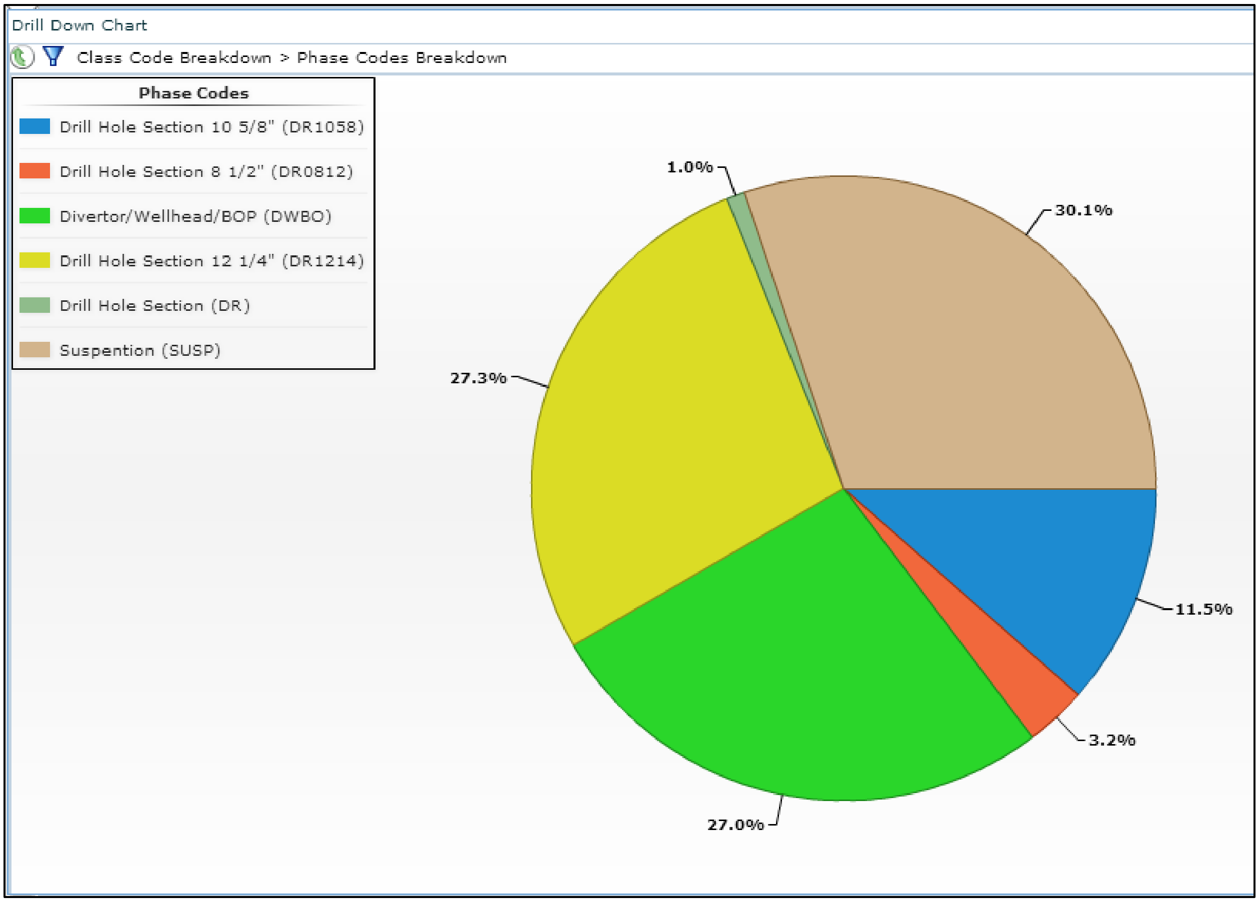

Figure 45: Geo Well #6; Percentage of Trouble during Programmed Phase Code Breakdown

Phase code Unprogrammed

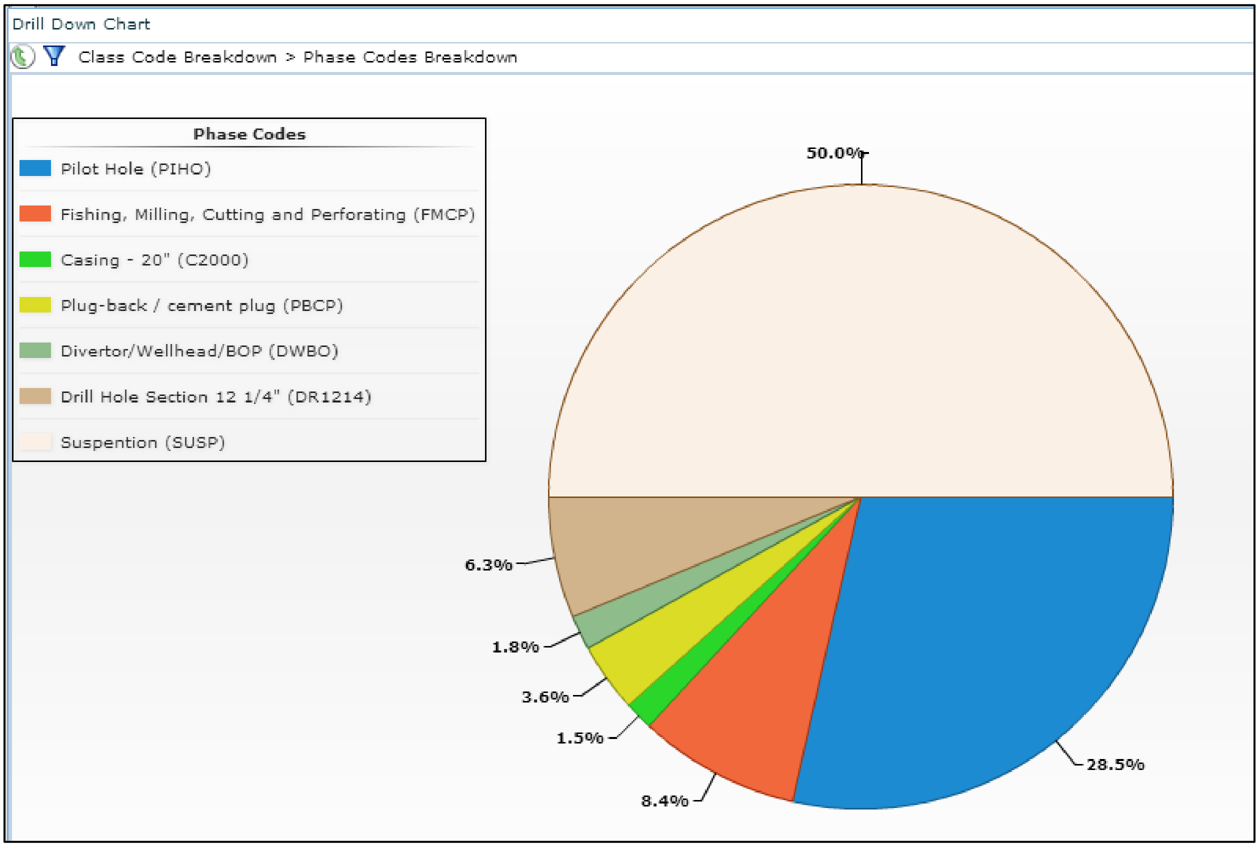

Figure 46: Geo Well #6; Percentage of Un-programmed Phase Code Breakdowns

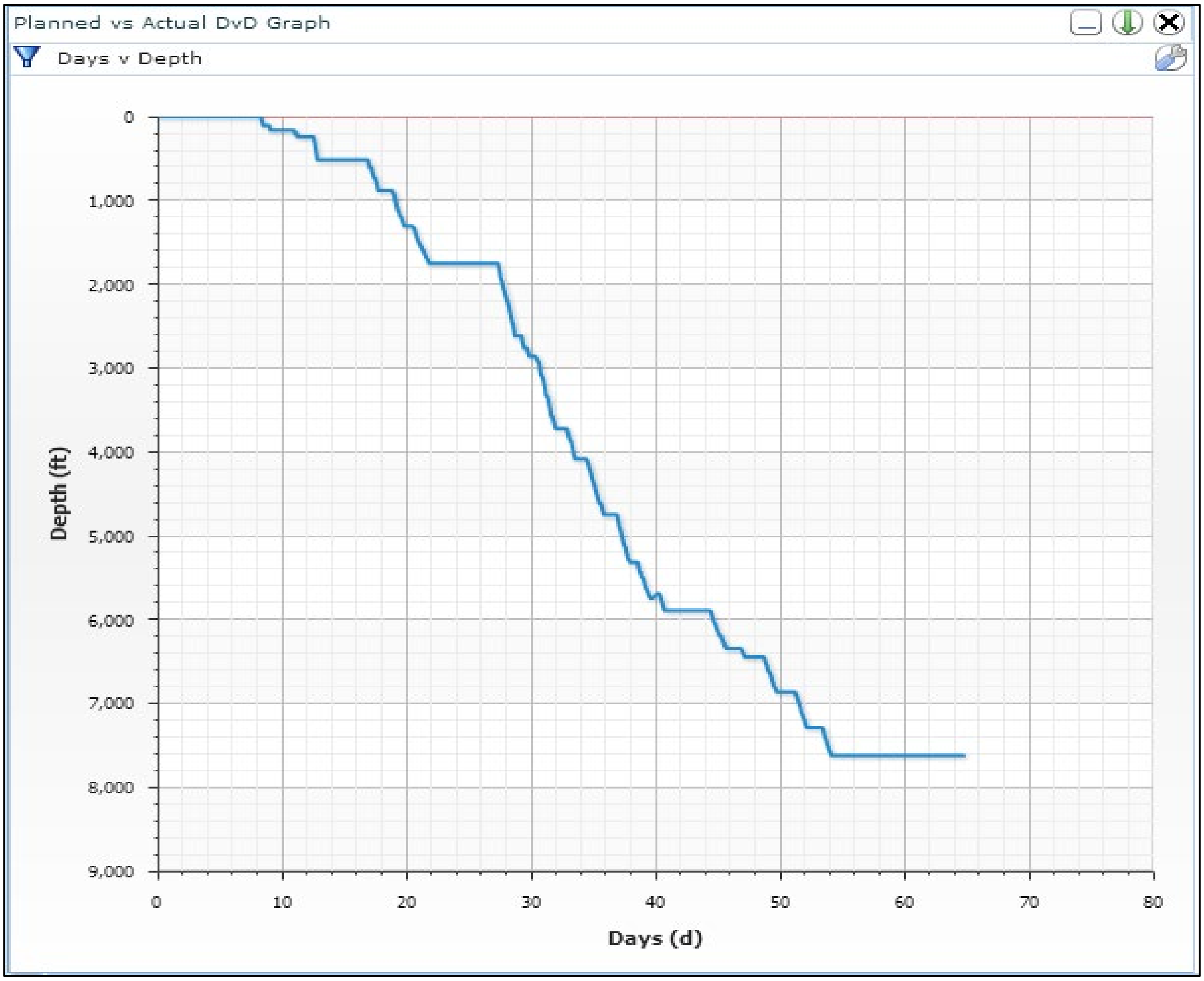

Figure 47: Geo Well #7; Days vs. Depth Drilled

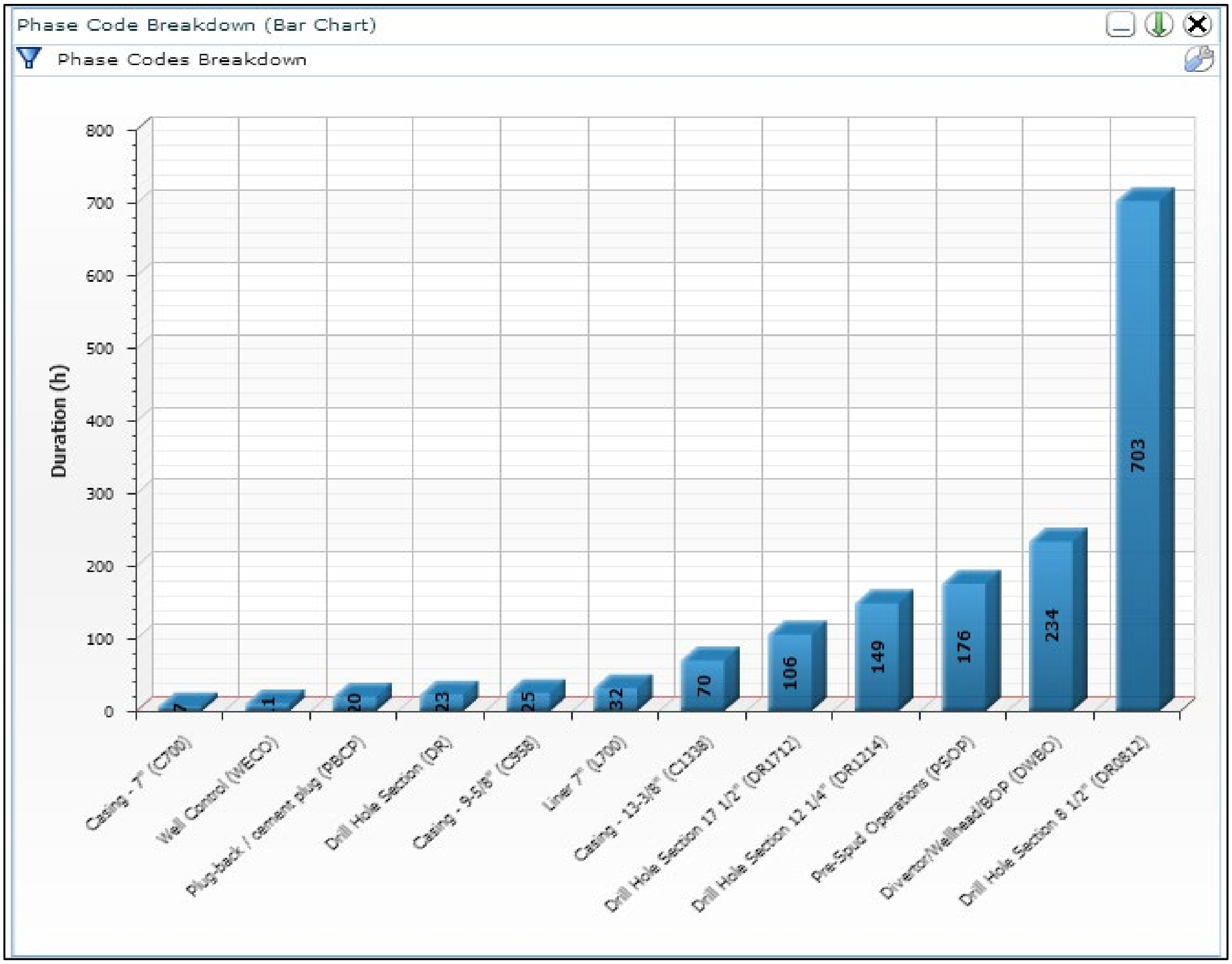

Figure 48: Geo Well #7; Phase Code Breakdown

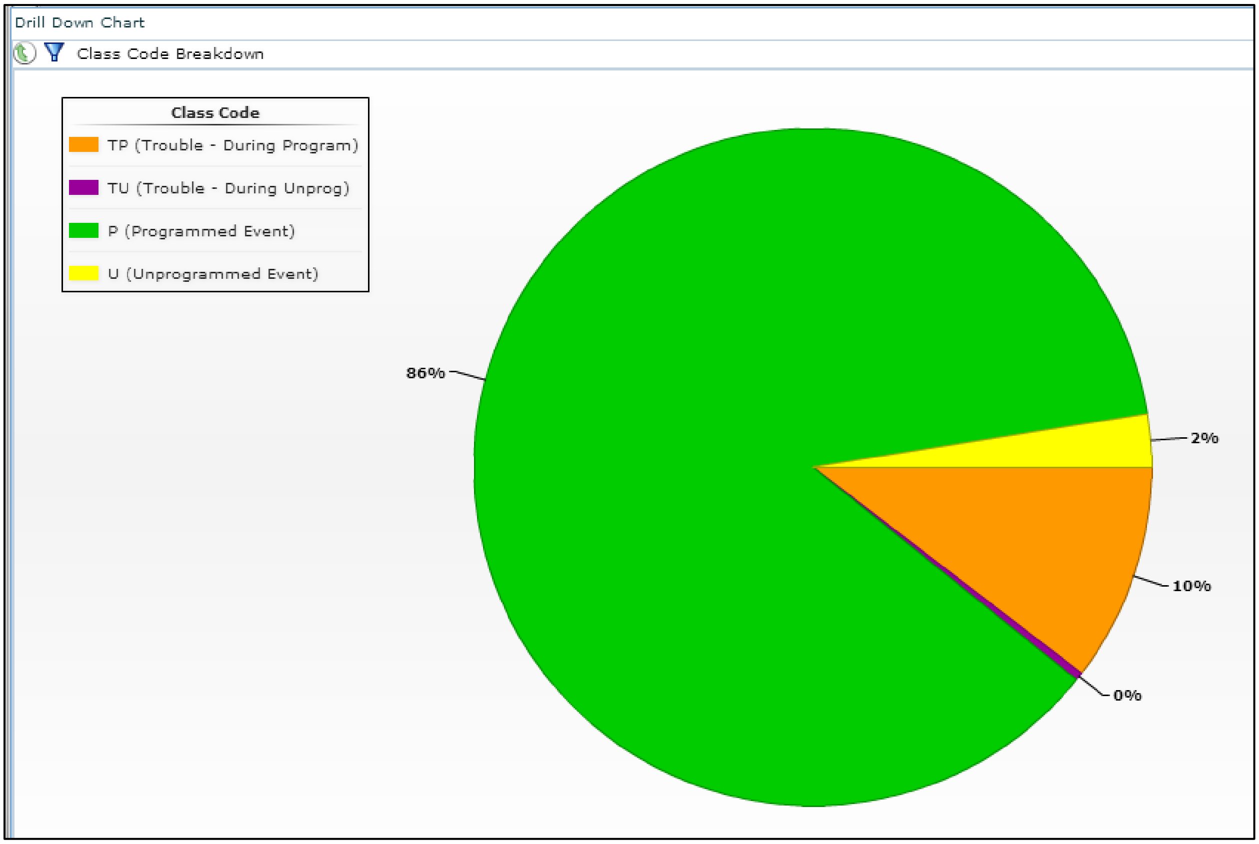

Figure 49: Geo Well #7; Percentage of Class Code Breakdown

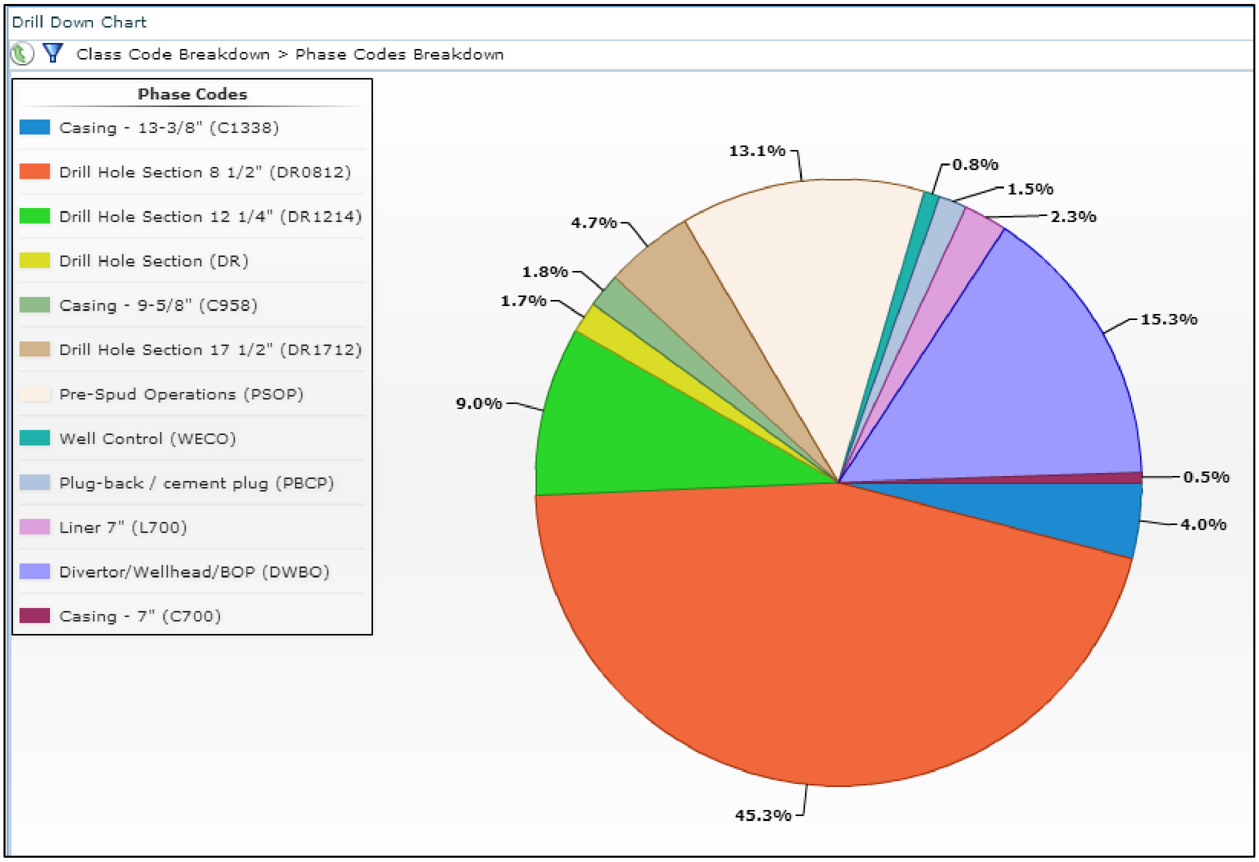

Figure 50: Geo Well #7; Percentage of Programmed Phase Code Breakdowns

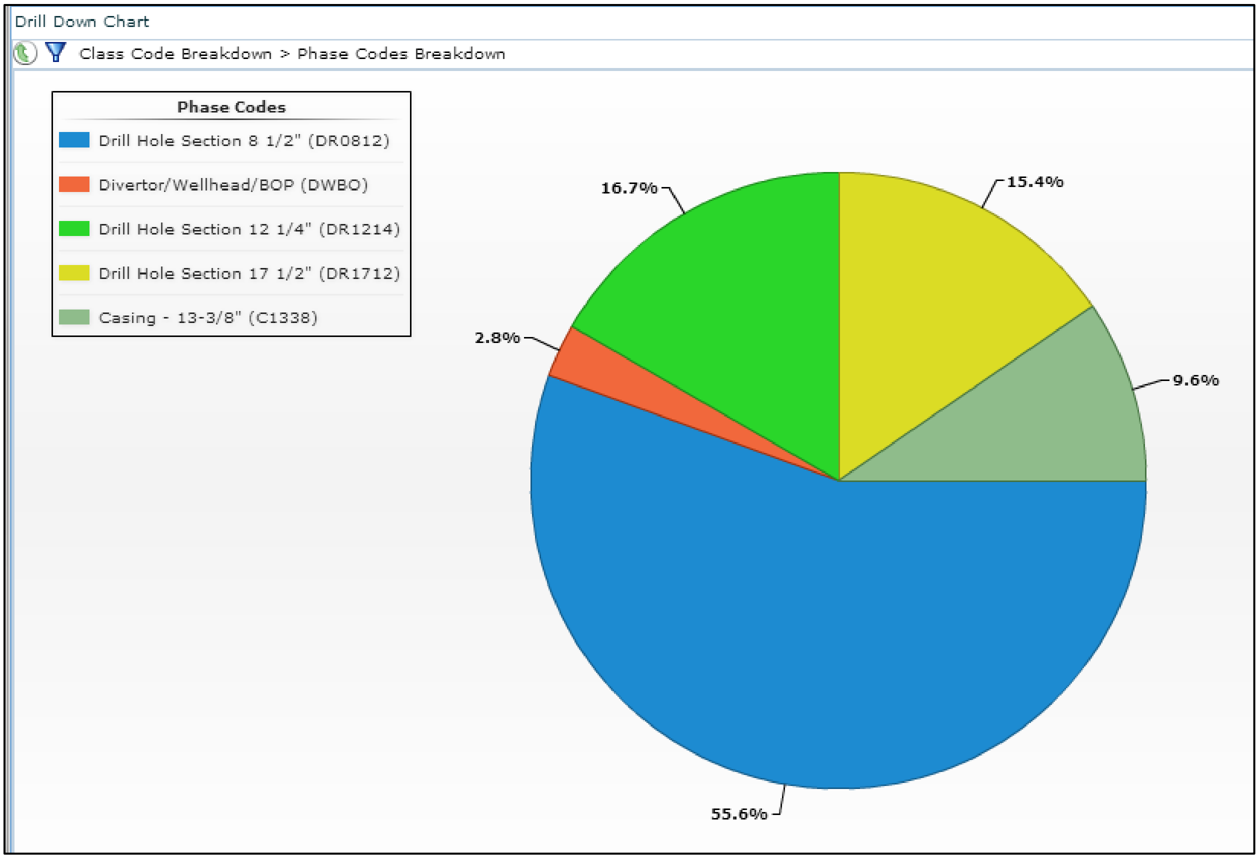

Figure 51: Geo Well #7; Percentage of Trouble during Programmed Phase Code Breakdowns

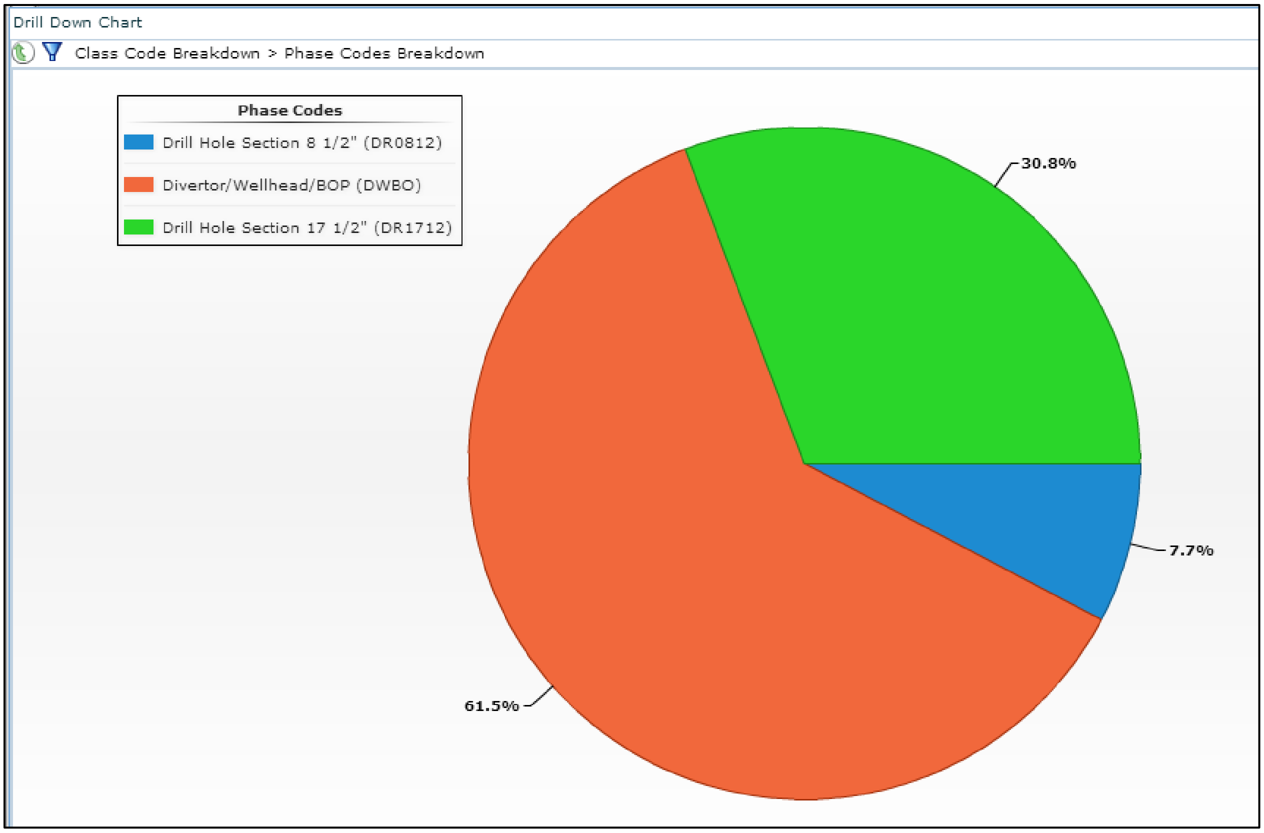

Figure 52: Geo Well #7; Percentage of Un-programmed Phase Code Breakdowns

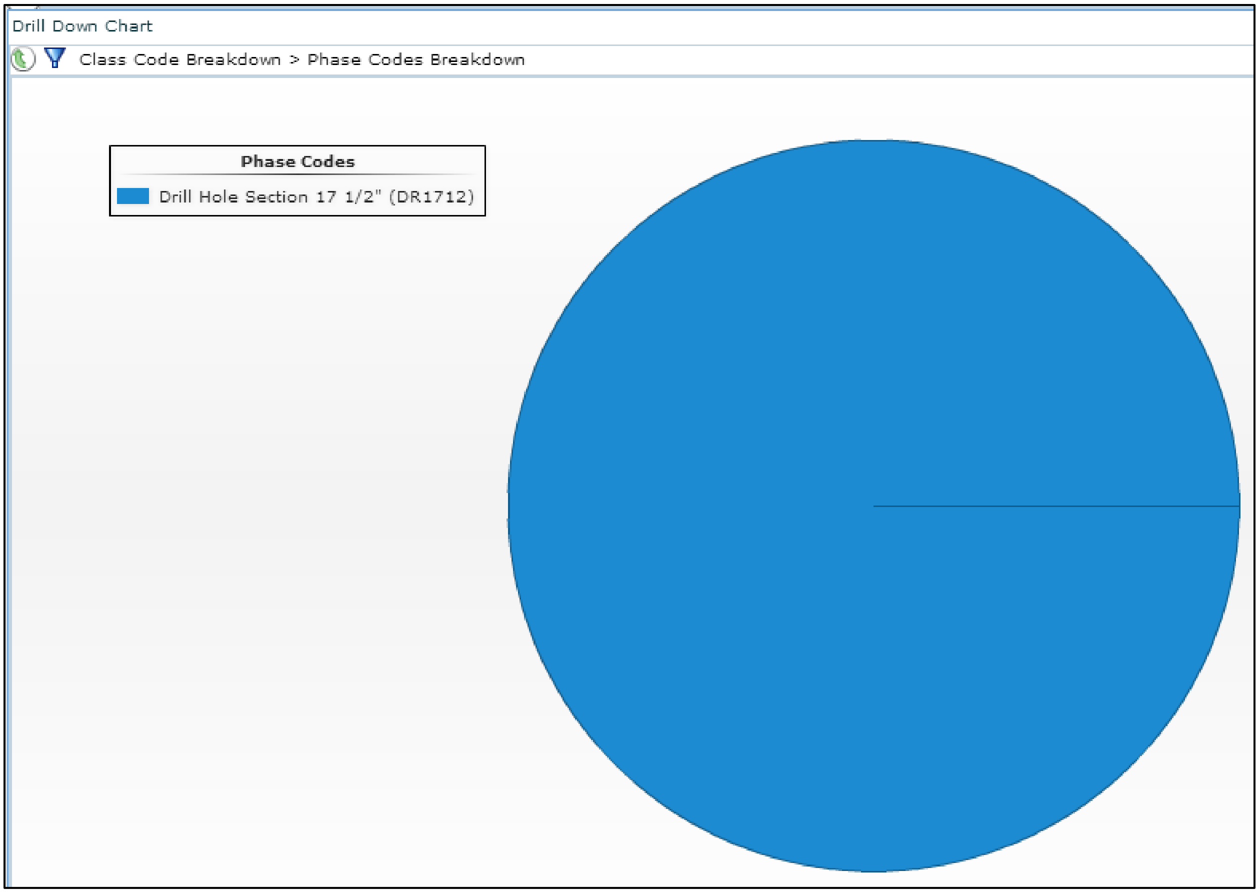

Figure 53: Geo Well #7; Percentage of Trouble during Un-Programmed Phase Code Breakdowns

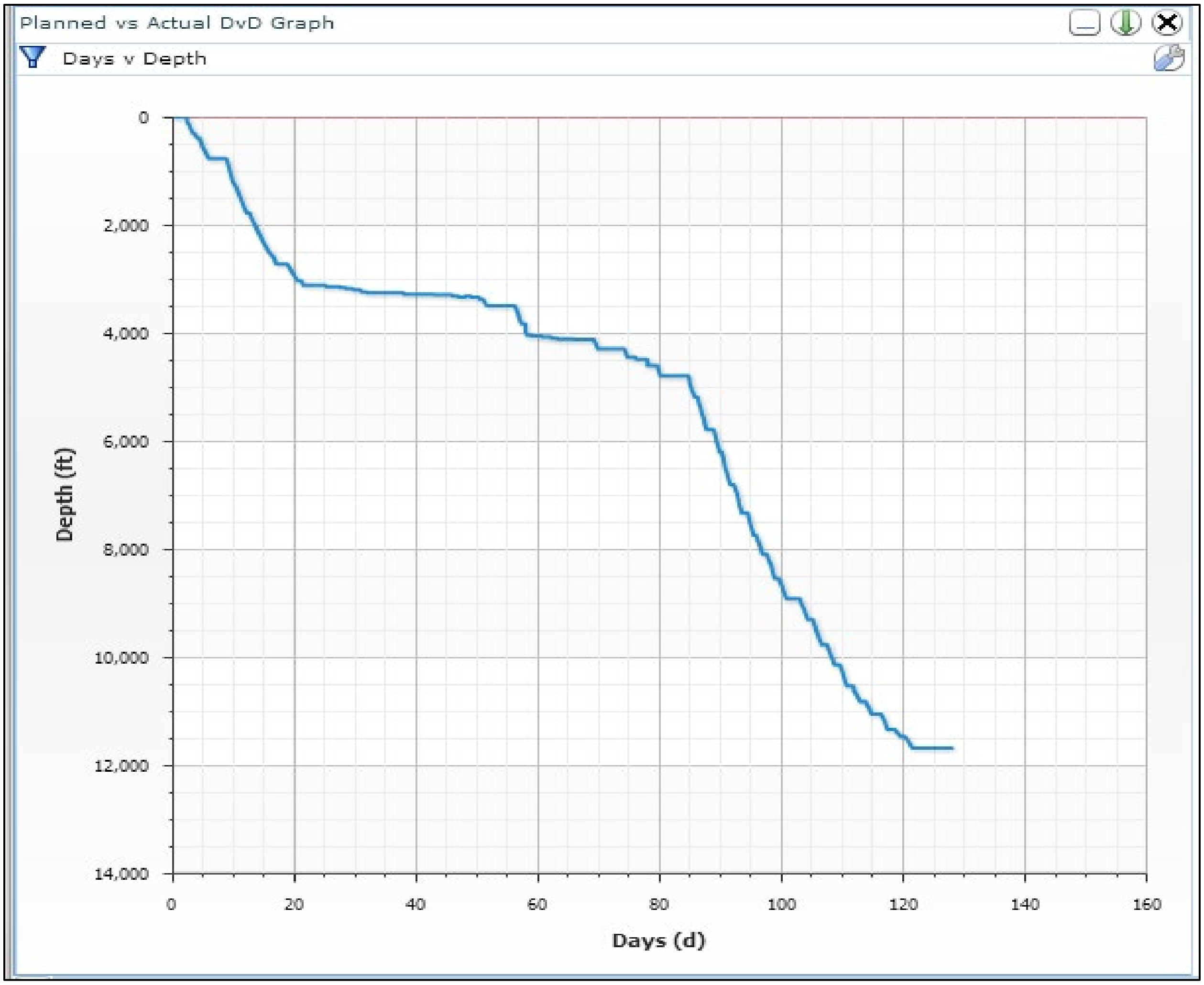

Figure 54: Geo Well #8; Days vs. Depth Drilled

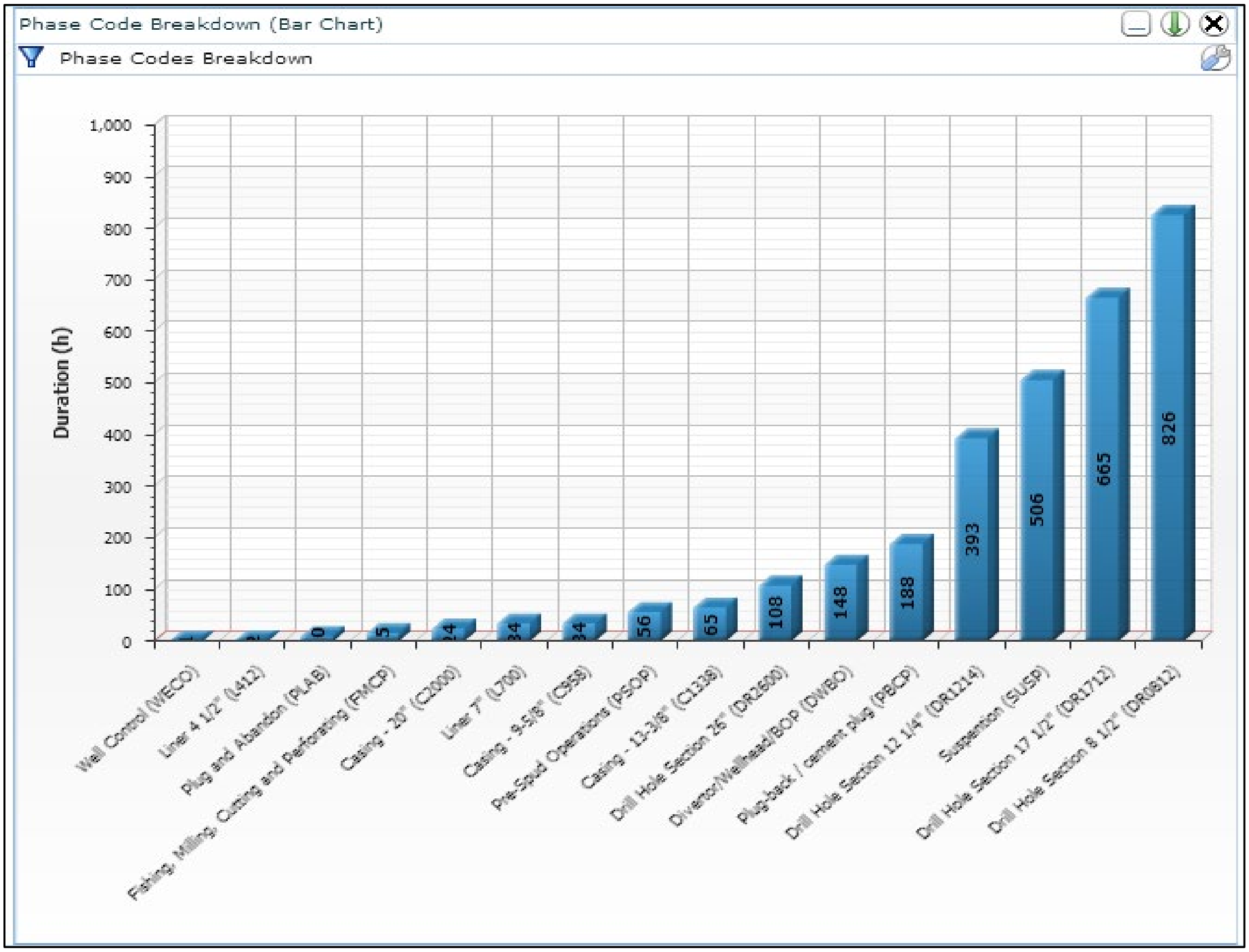

Figure 55: Geo Well #8; Phase Code Breakdown

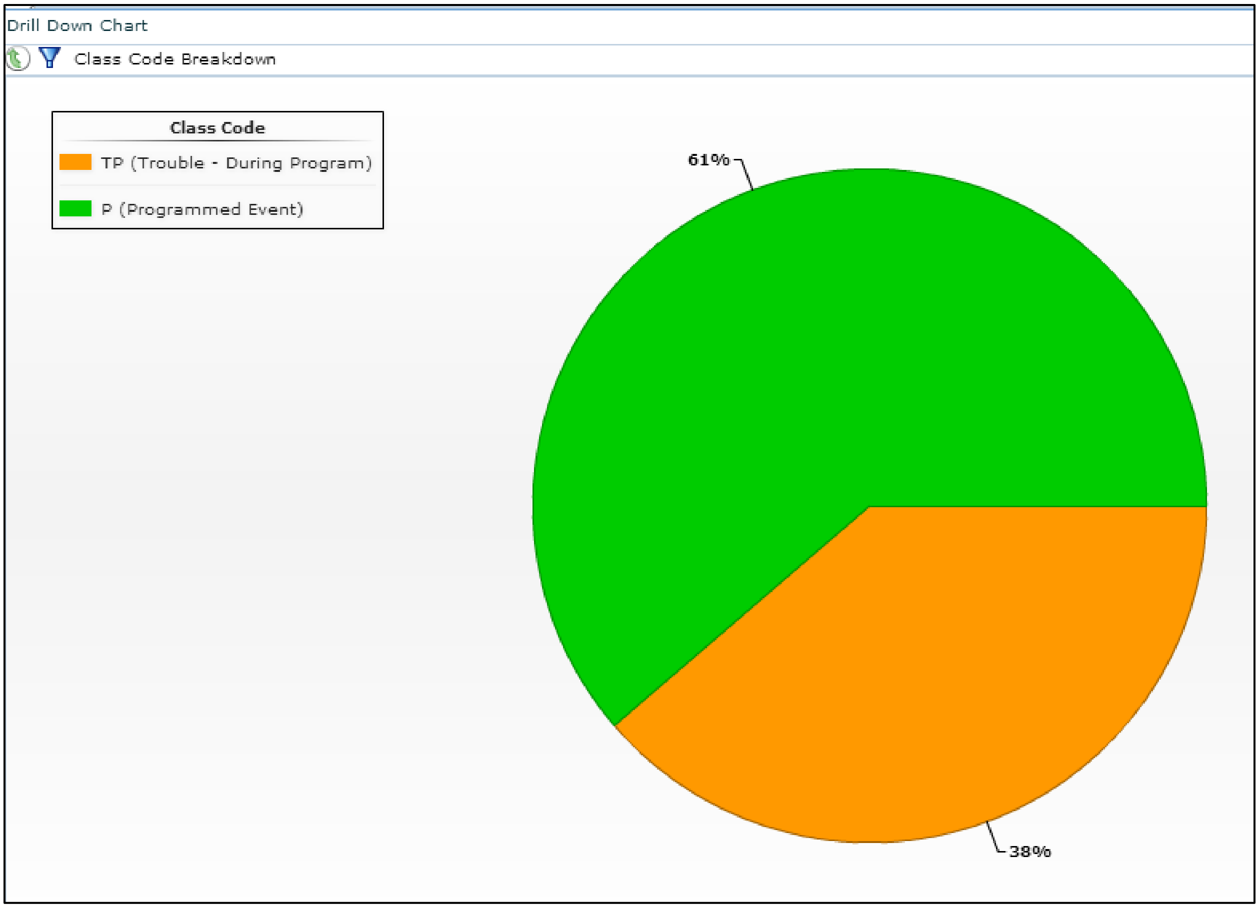

Figure 56: Geo Well #8; Percentage of Class Code Breakdowns

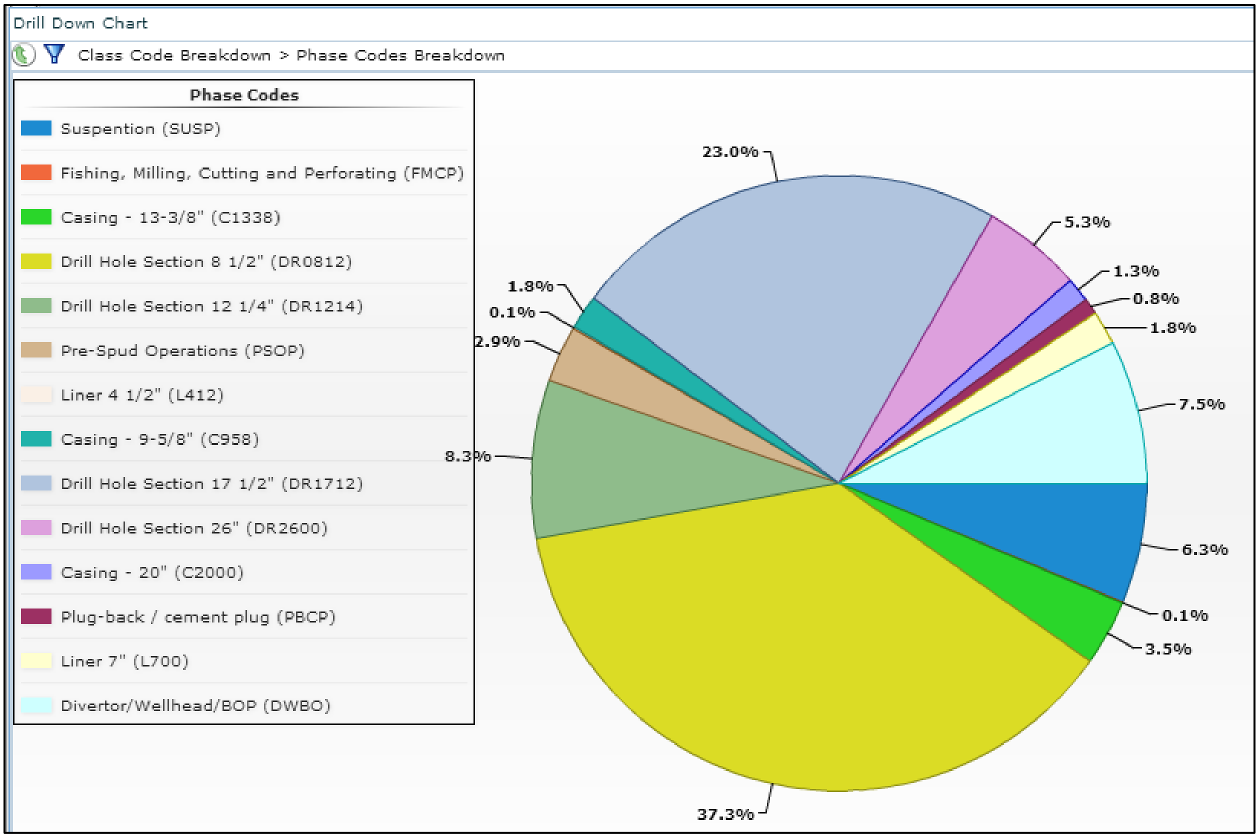

Figure 57: Geo Well #8; Percentage of Programmed Phase Code Breakdowns

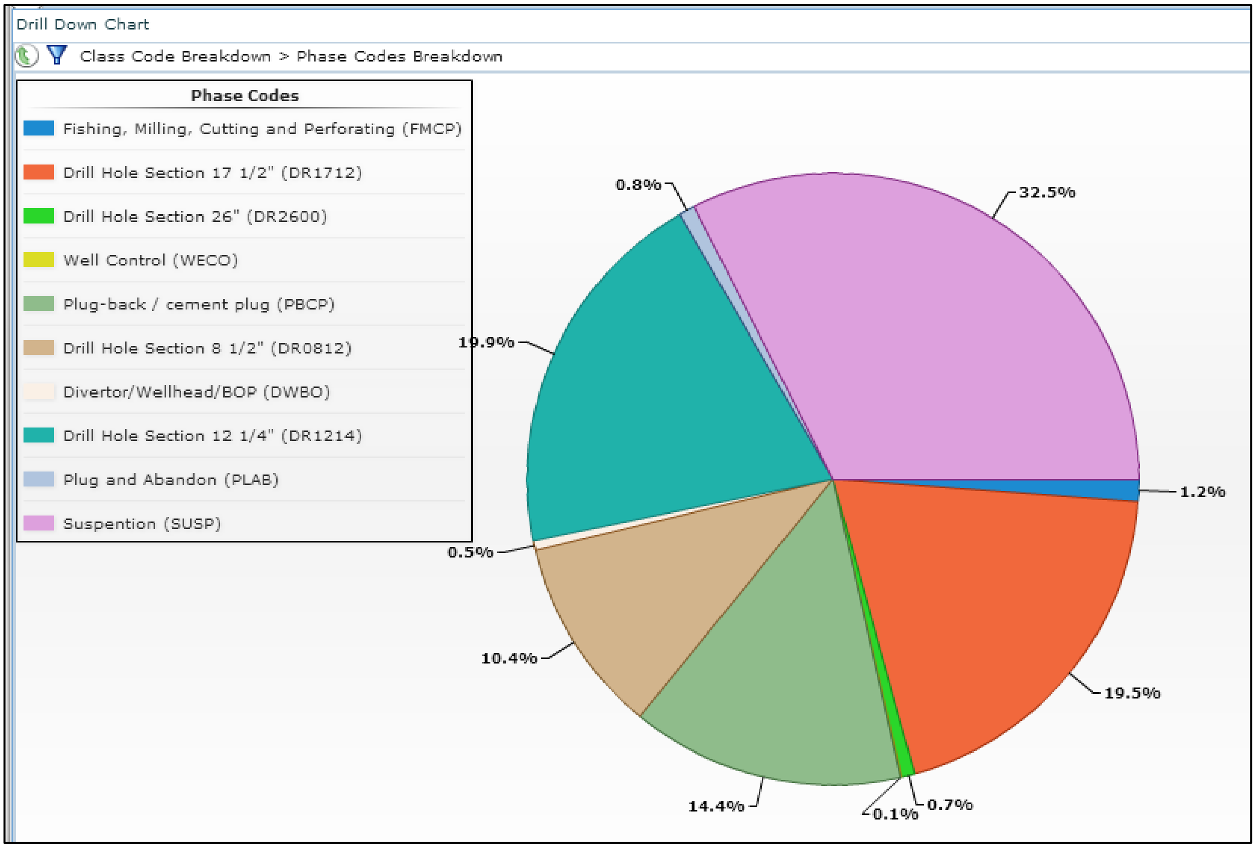

Figure 58: Geo Well #8; Percentage of Trouble during Programmed Phase Code Breakdowns

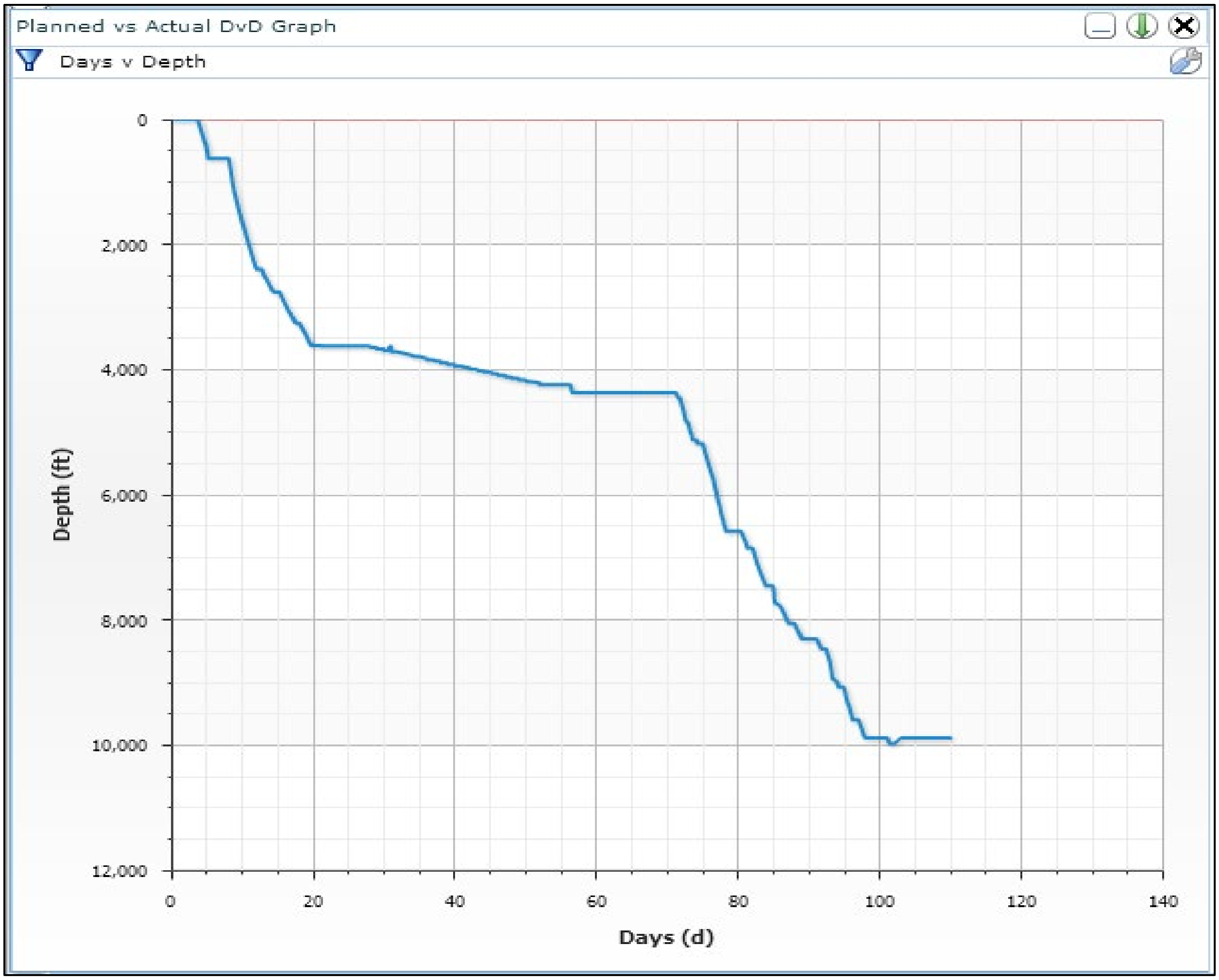

Figure 59: Geo Well #9; Days vs. Depth Drilled

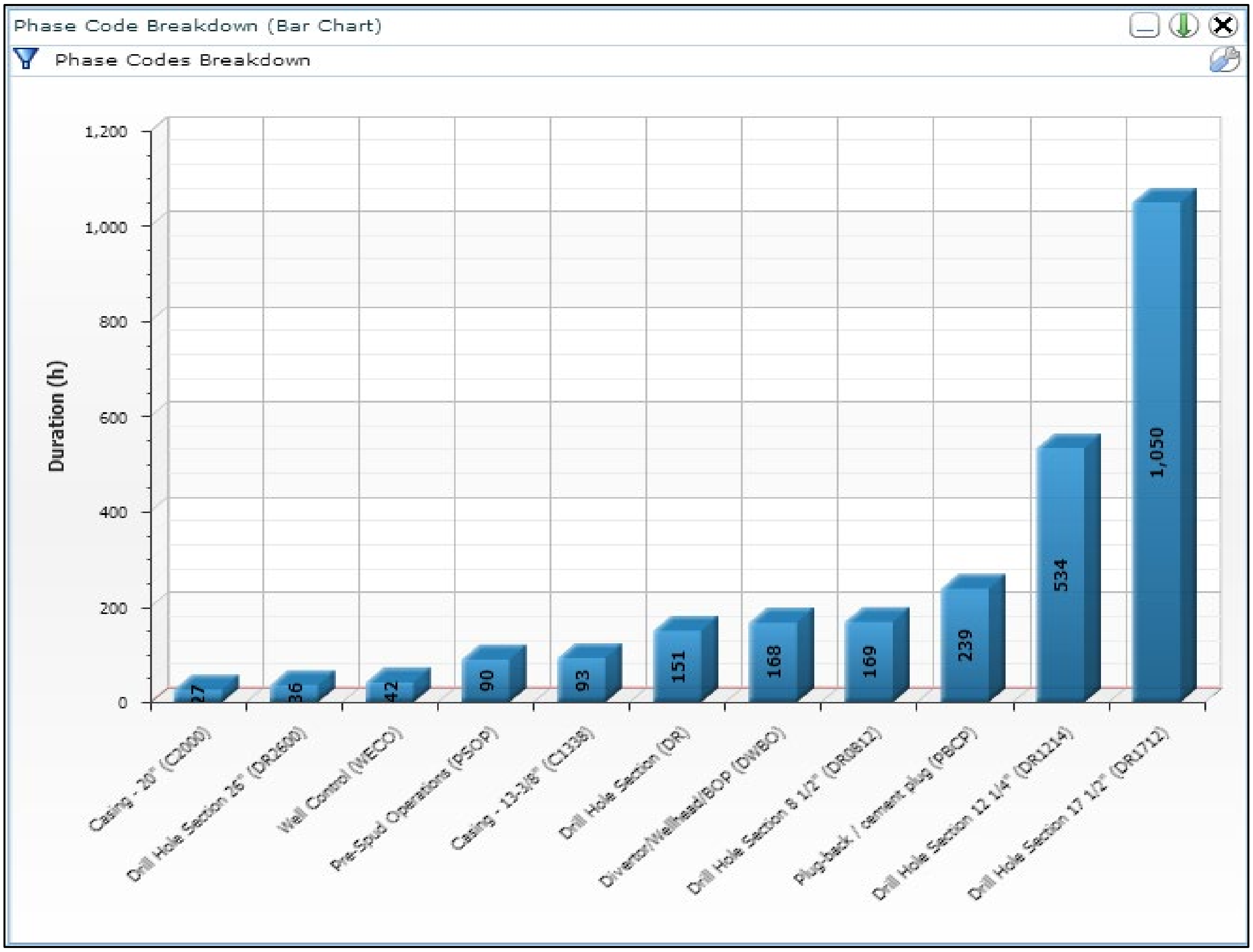

Figure 60: Geo Well #9; Phase Code Breakdown

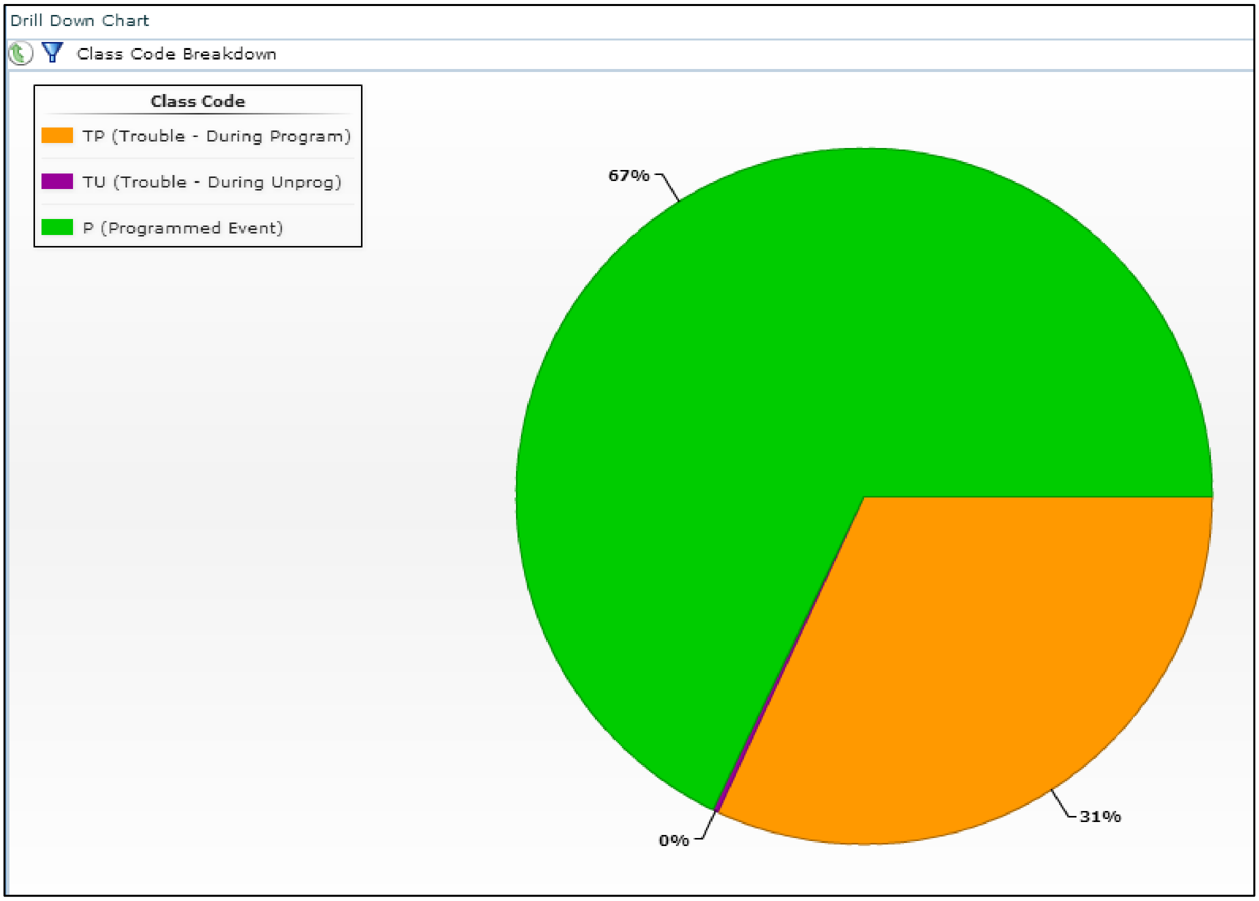

Figure 61: Geo Well #9; Percentage of Class Code Breakdowns

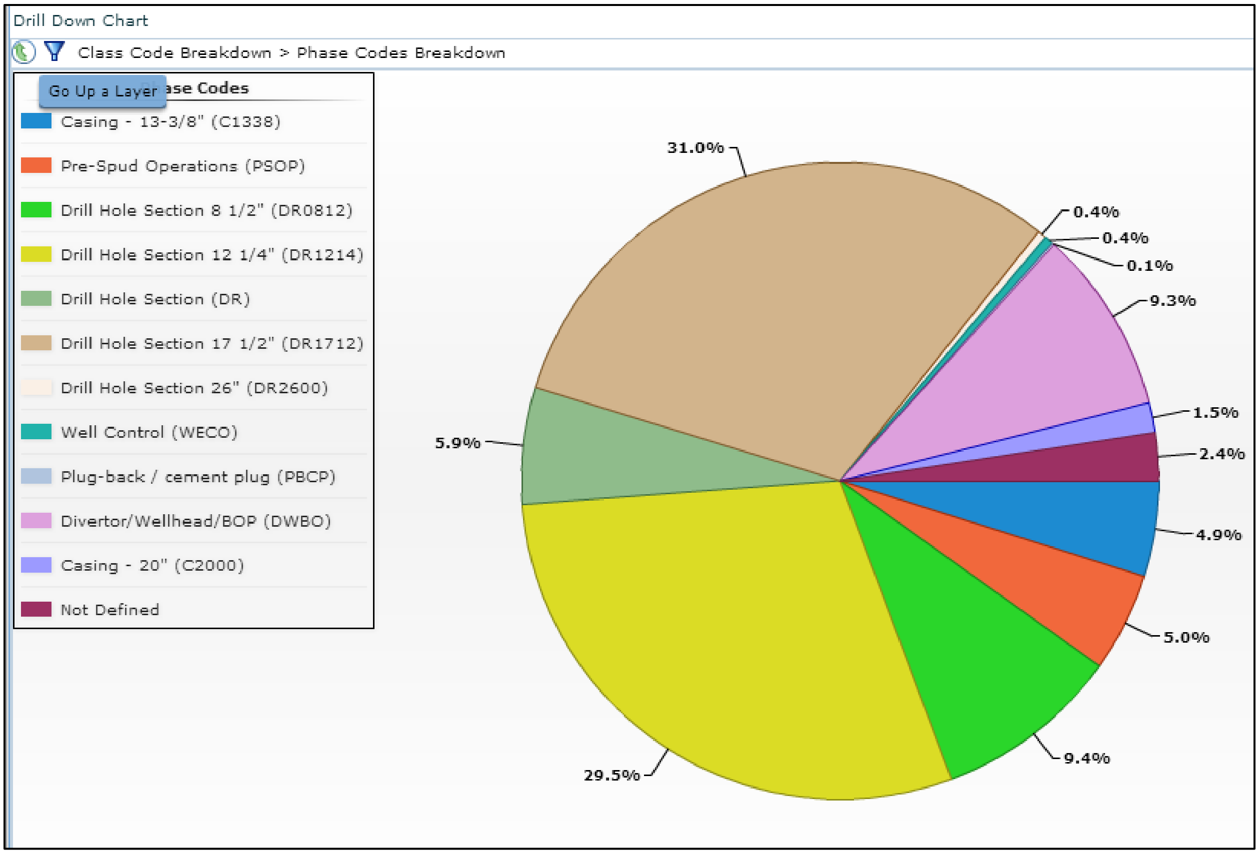

Figure 62: Geo Well #9; Percentage of Programmed Phase Code Breakdowns

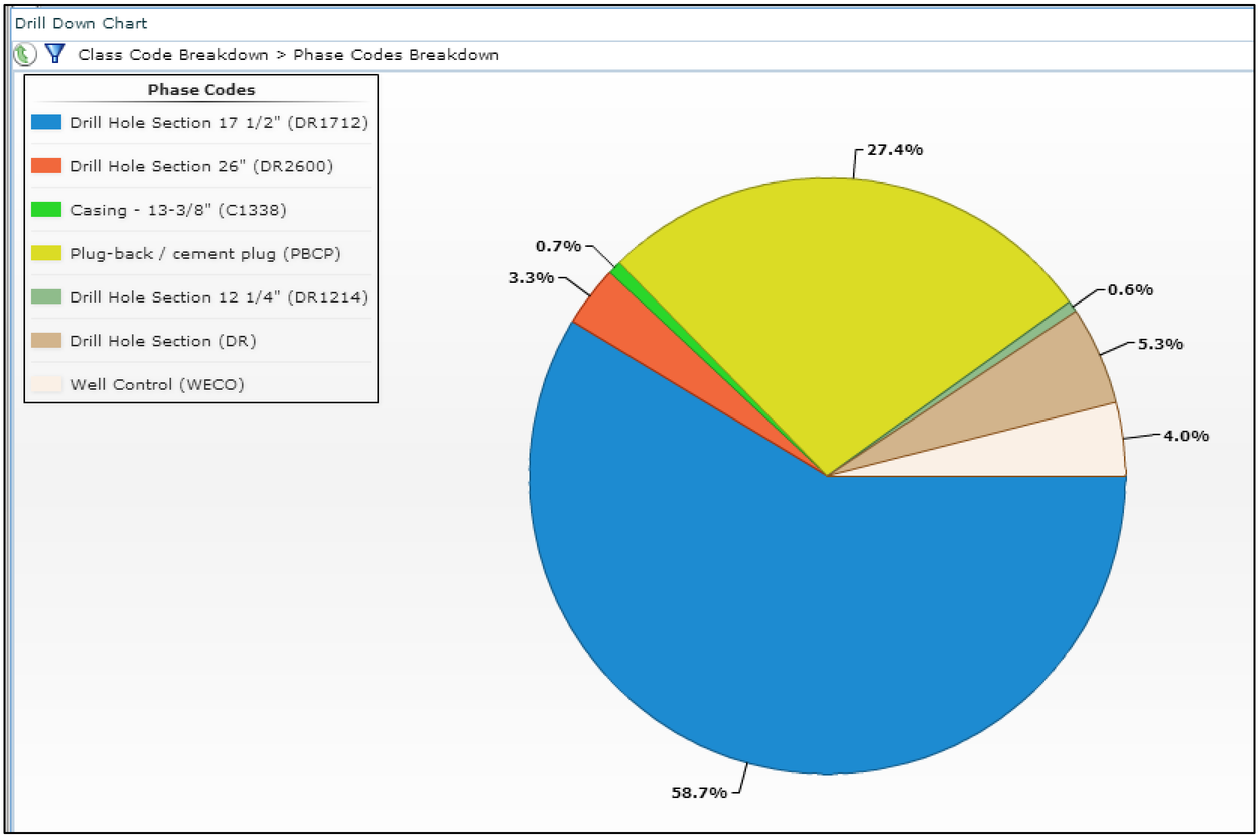

Figure 63: Geo Well #9; Percentage of Trouble during Programmed Phase Code Breakdowns

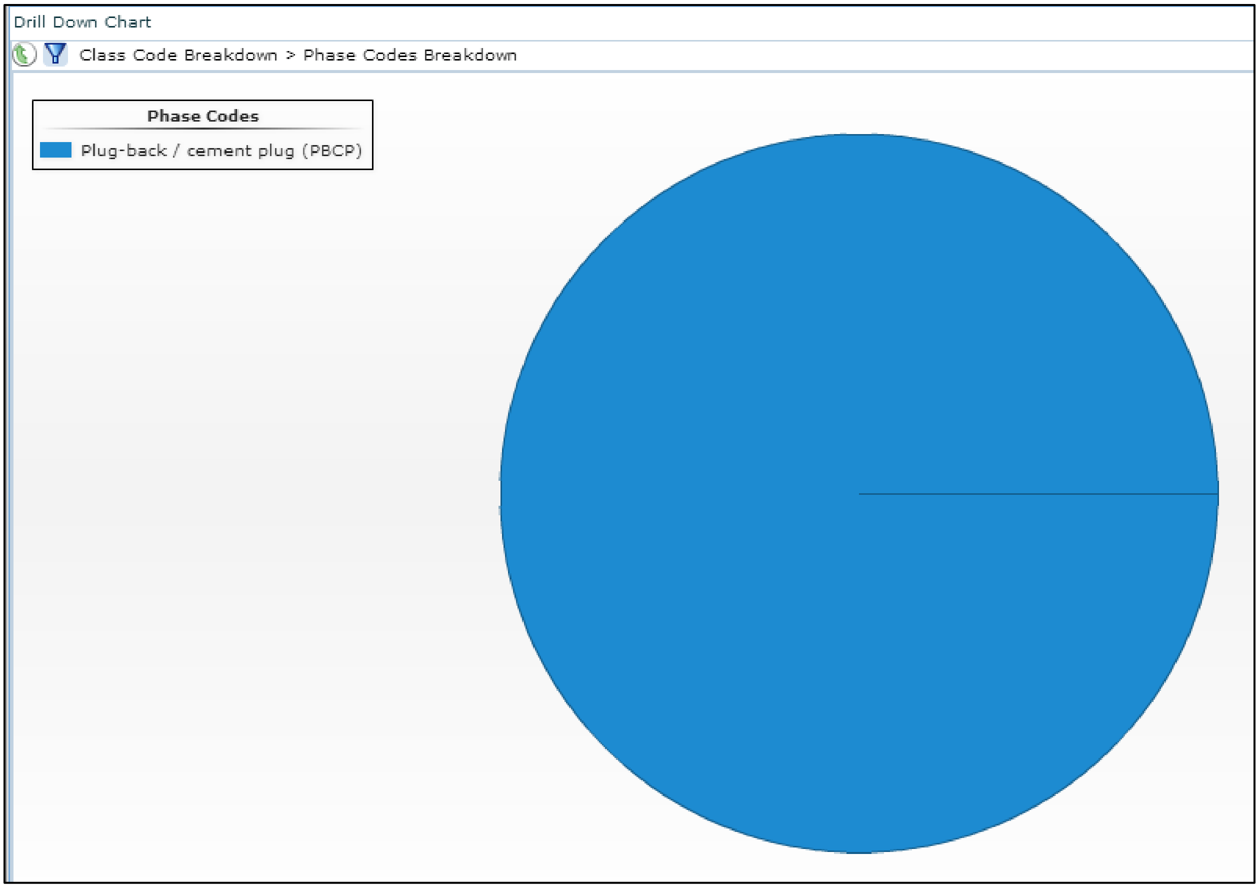

Figure 64: Geo Well #9; Percentage of Un-Programmed Phase Code Breakdowns

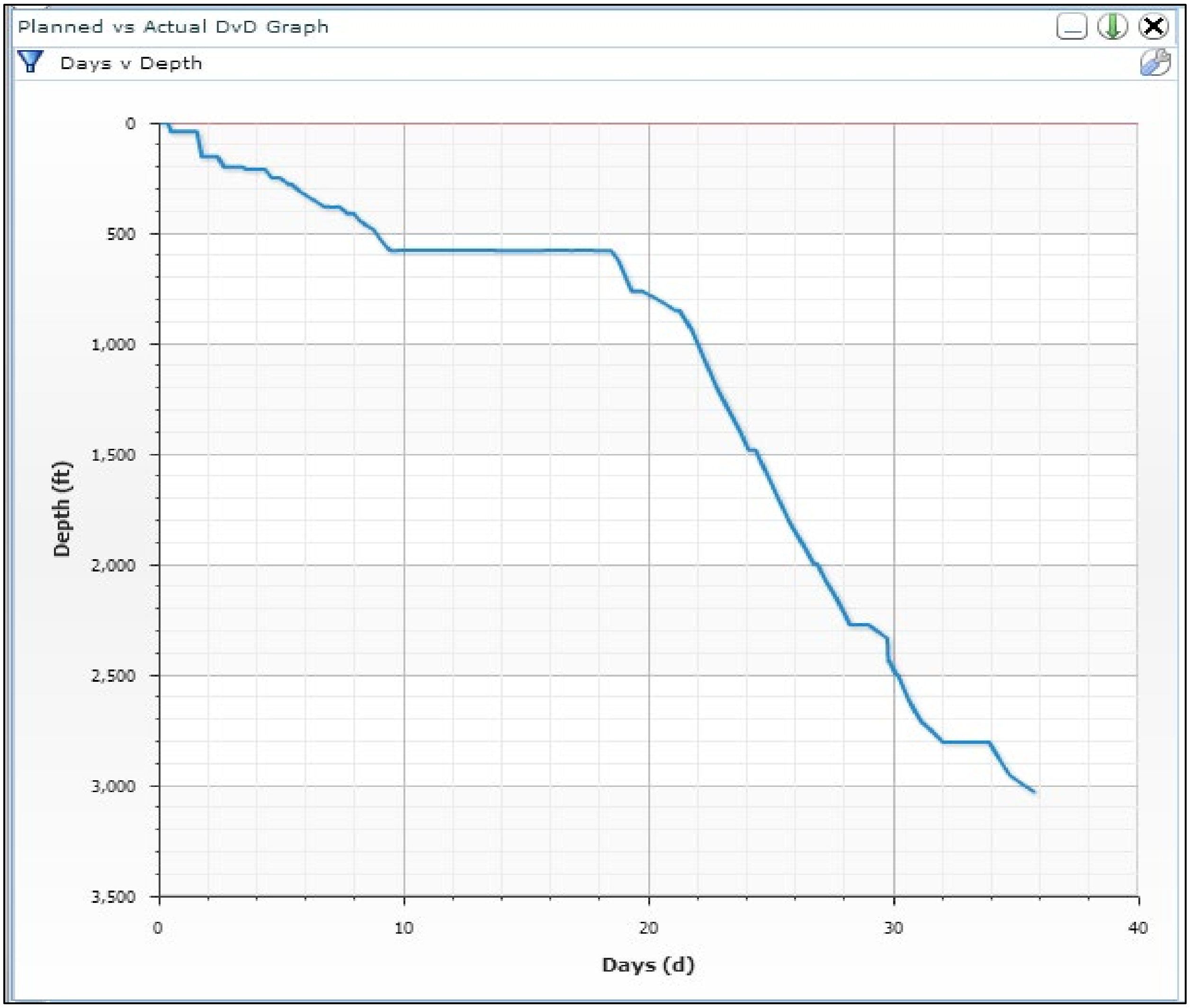

Figure 65: Geo Well #10; Days vs. Depth Drilled

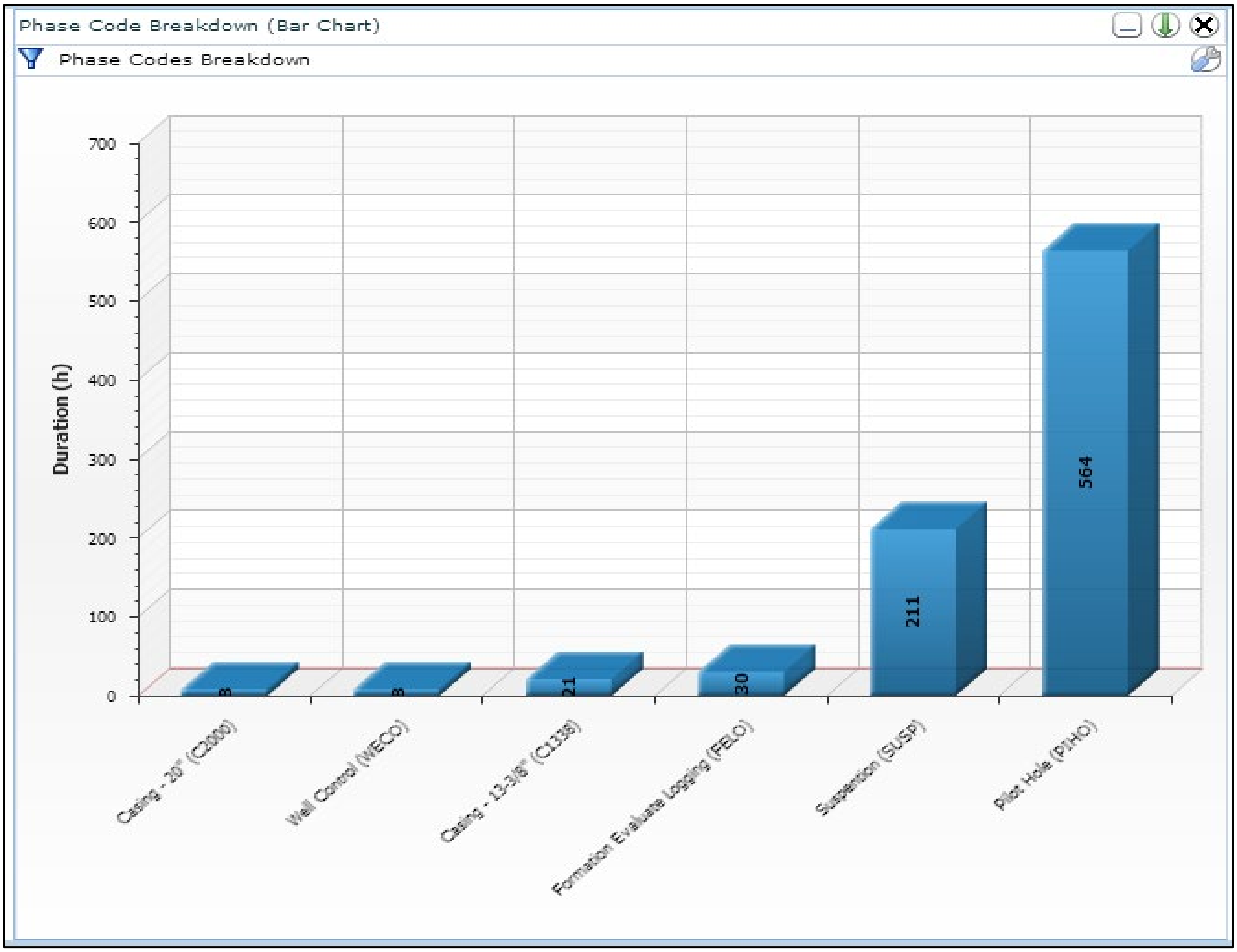

Figure 66: Geo Well #10; Phase Code Breakdown

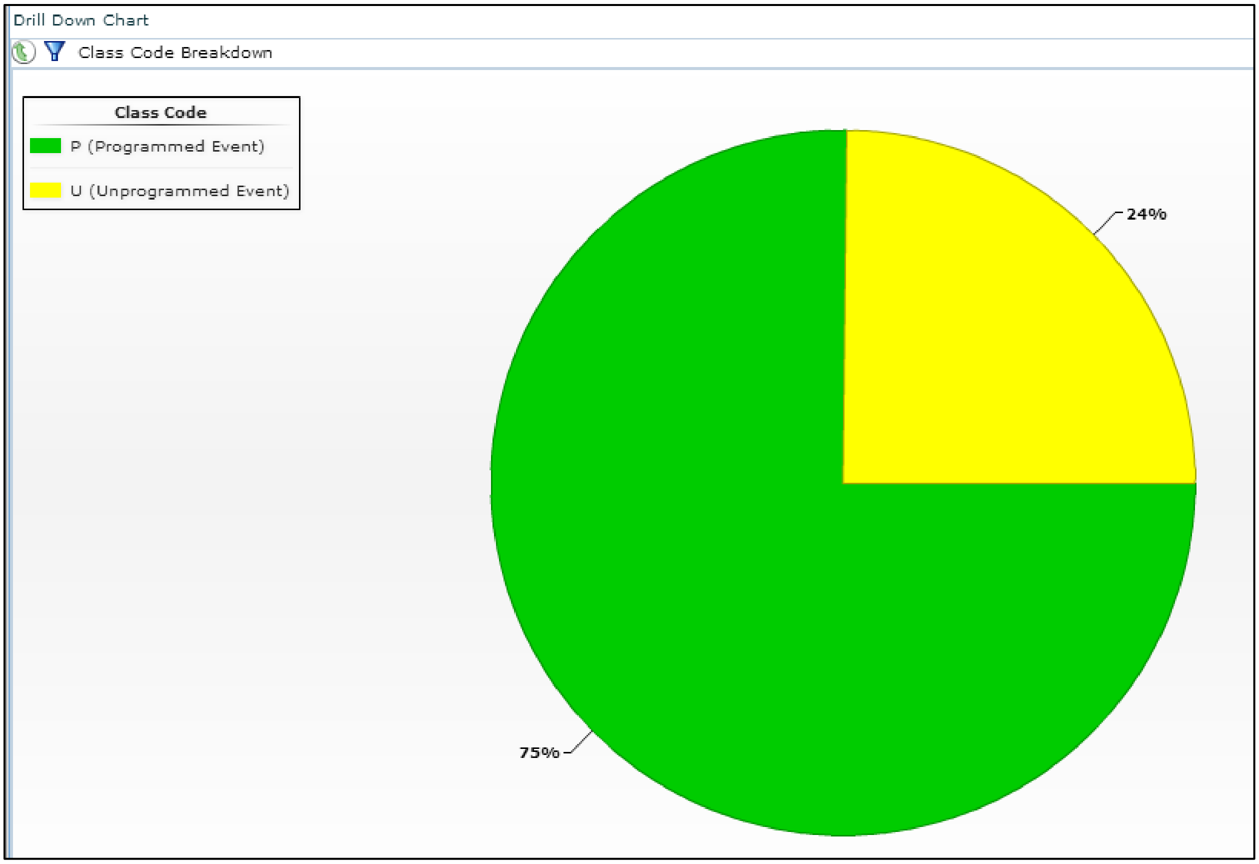

Figure 67: Geo Well #10; Percentage of Class Code Breakdowns

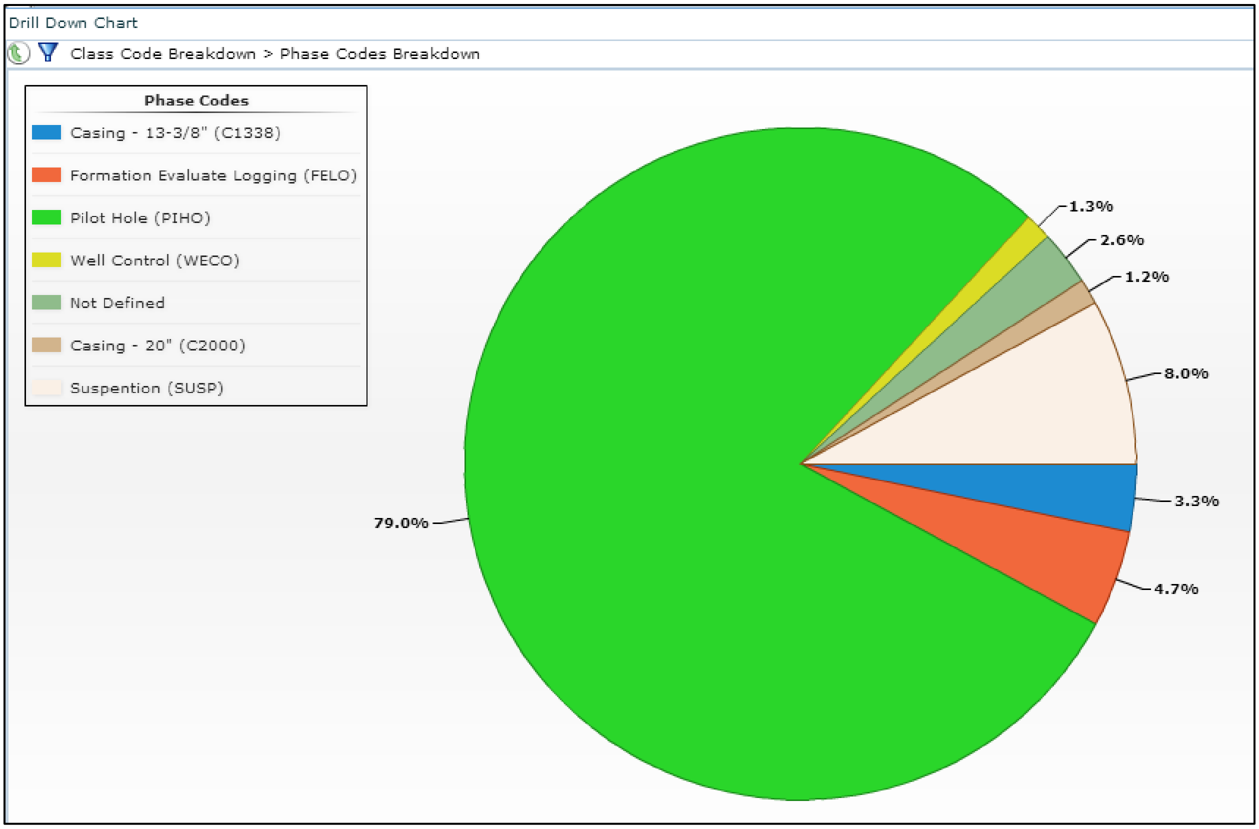

Figure 68: Geo Well #10; Percentage of Programmed Phase Code Breakdowns

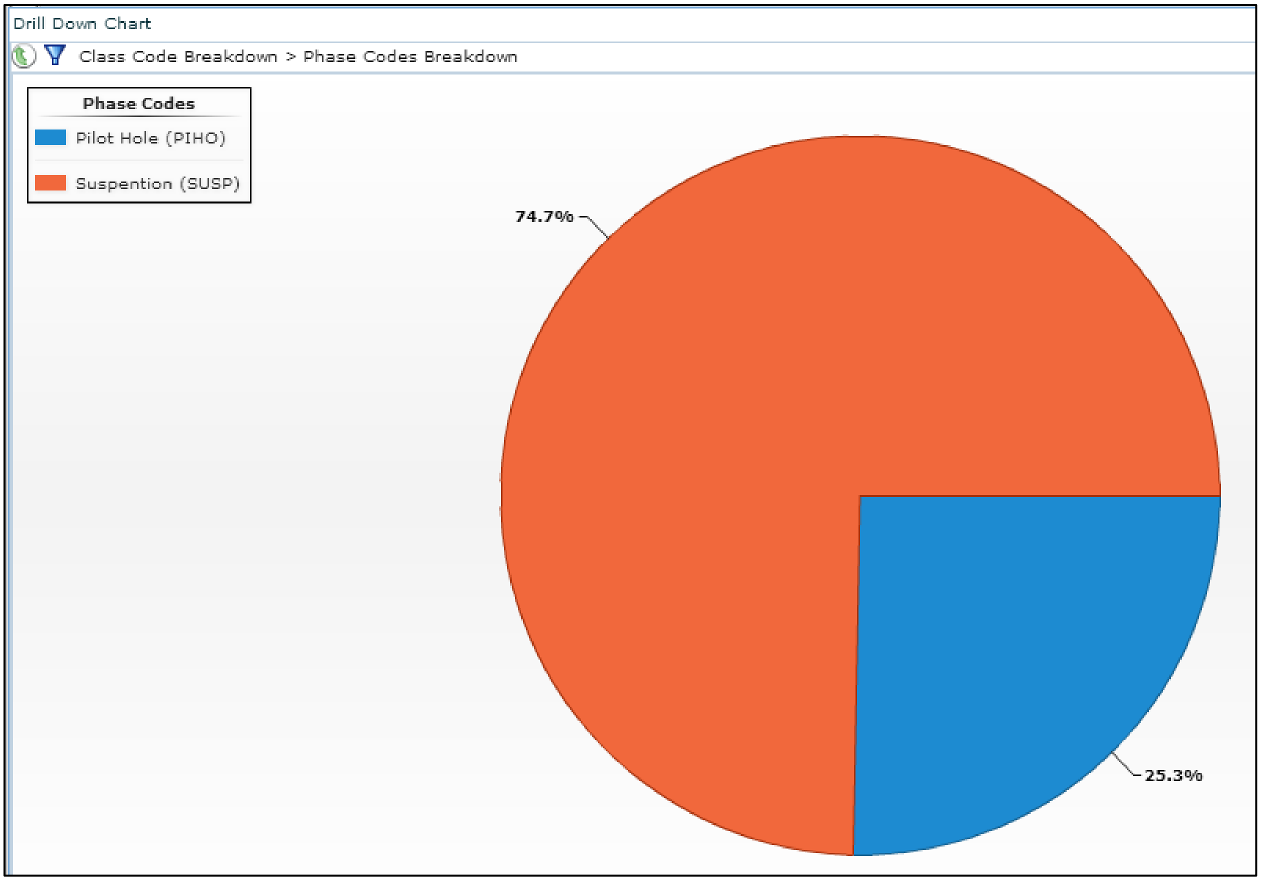

Figure 69: Geo Well #10; Percentage of Un-Programmed Phase Code Breakdowns

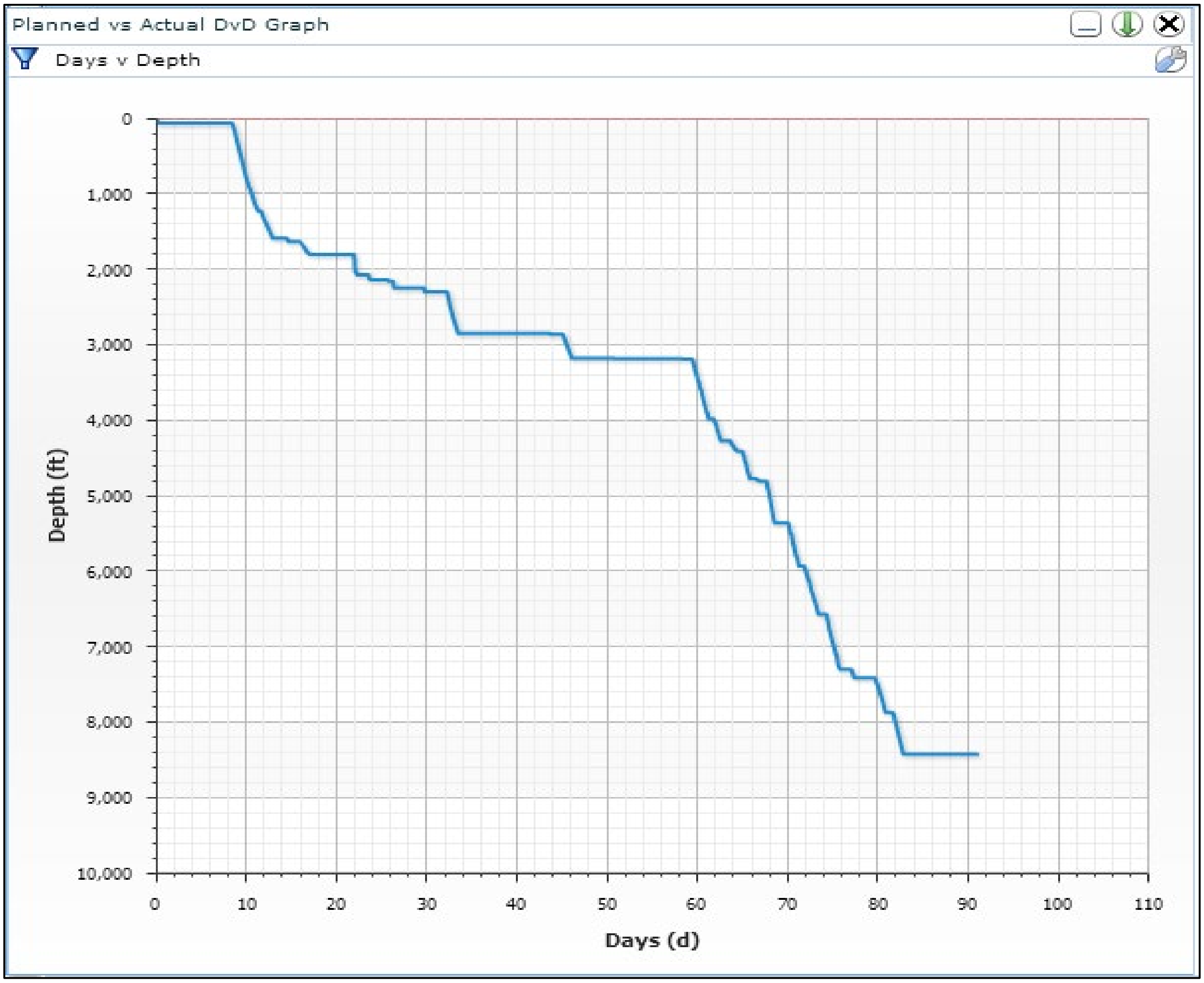

Figure 70: Geo Well #11; Days vs. Depth Drilled

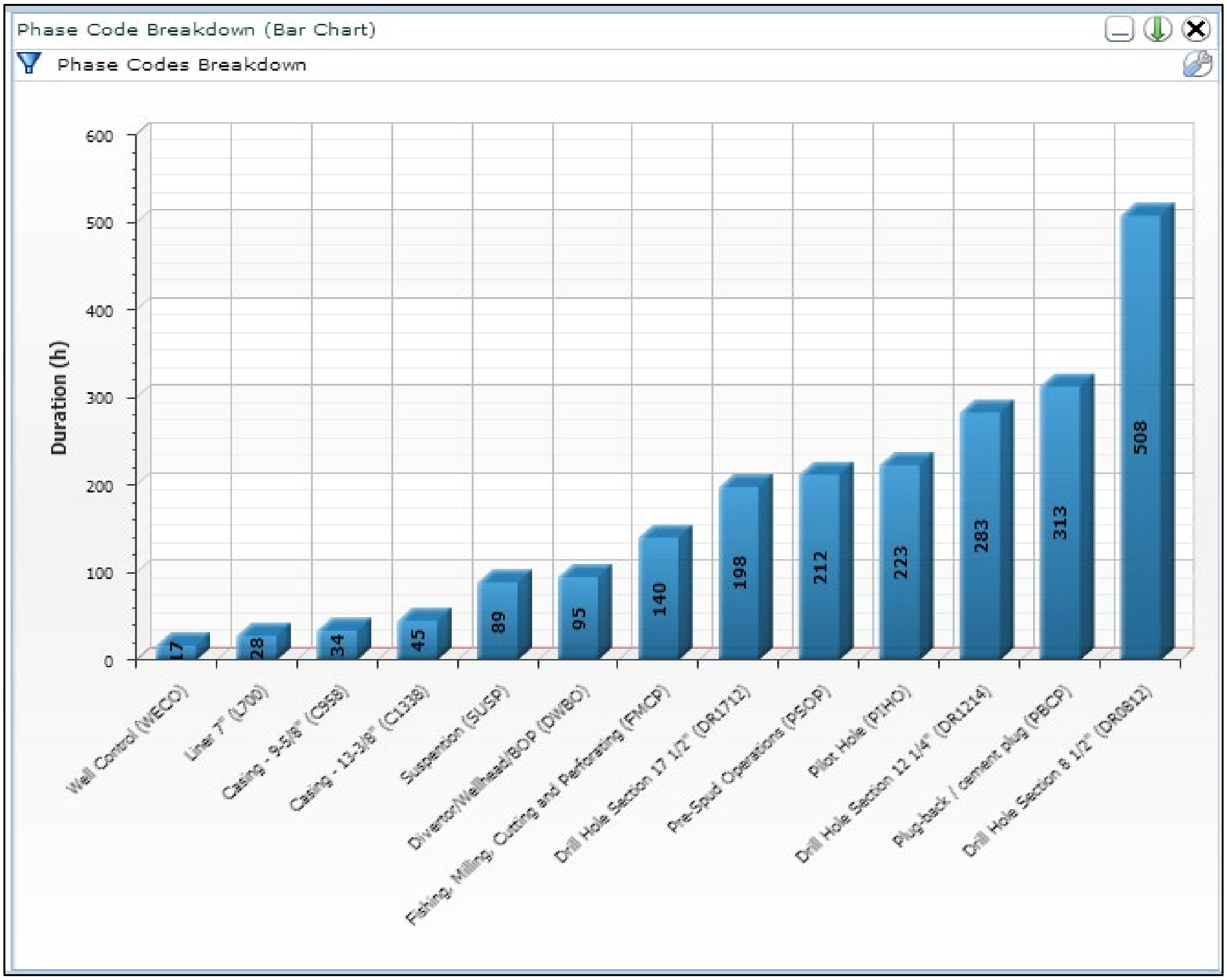

Figure 71: Geo Well #11; Phase Code Breakdown

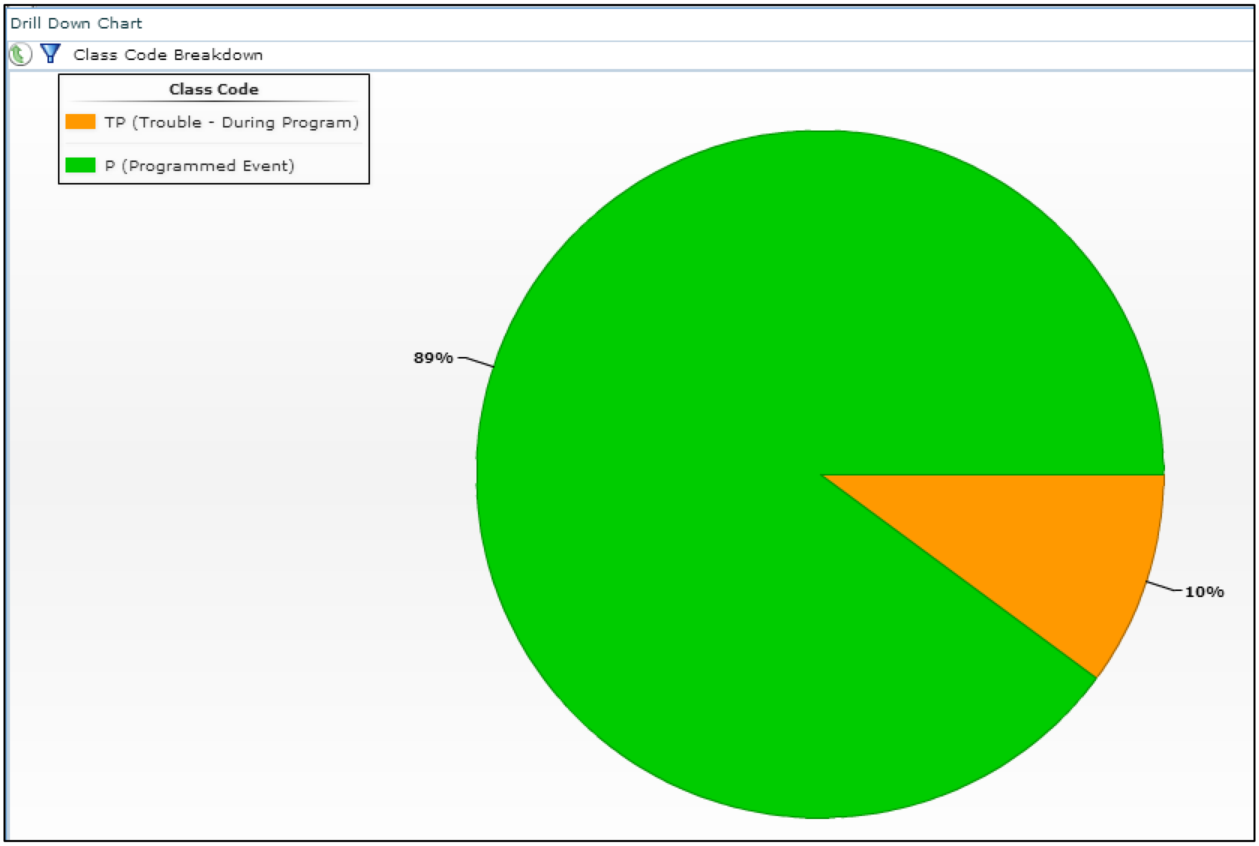

Figure 72: Geo Well #11; Percentage of Class Code Breakdowns

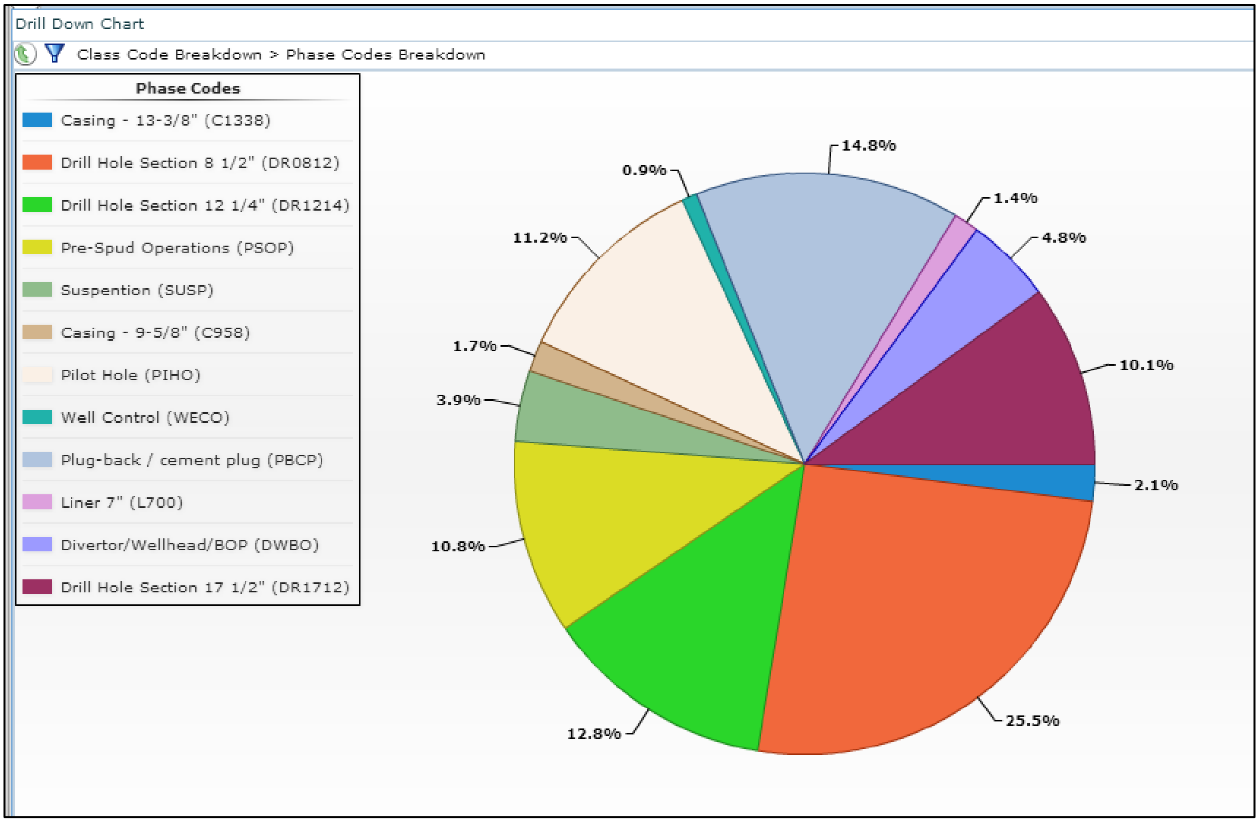

Figure 73: Geo Well #11; Percentage of Programmed Phase Code Breakdowns

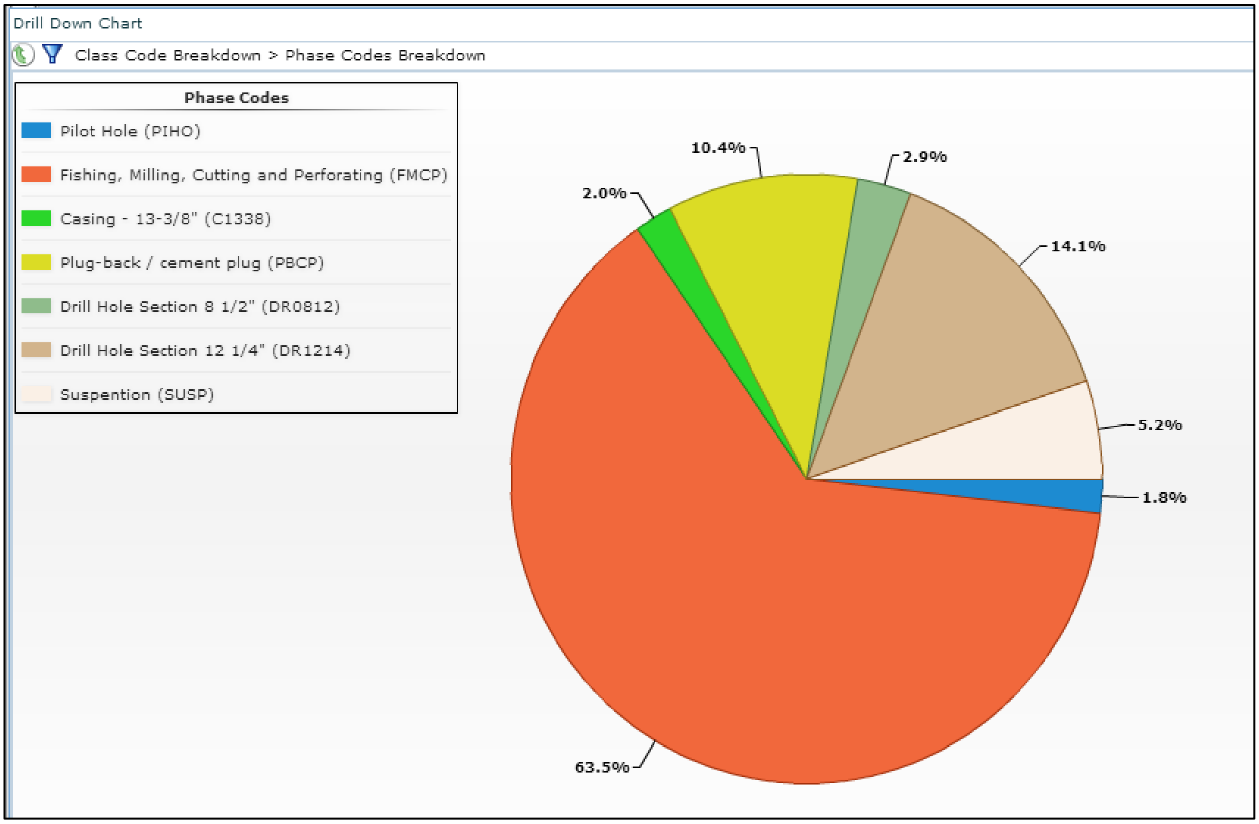

Figure 74: Geo Well #11; Percentage of Trouble during Programmed Phase Code Breakdowns

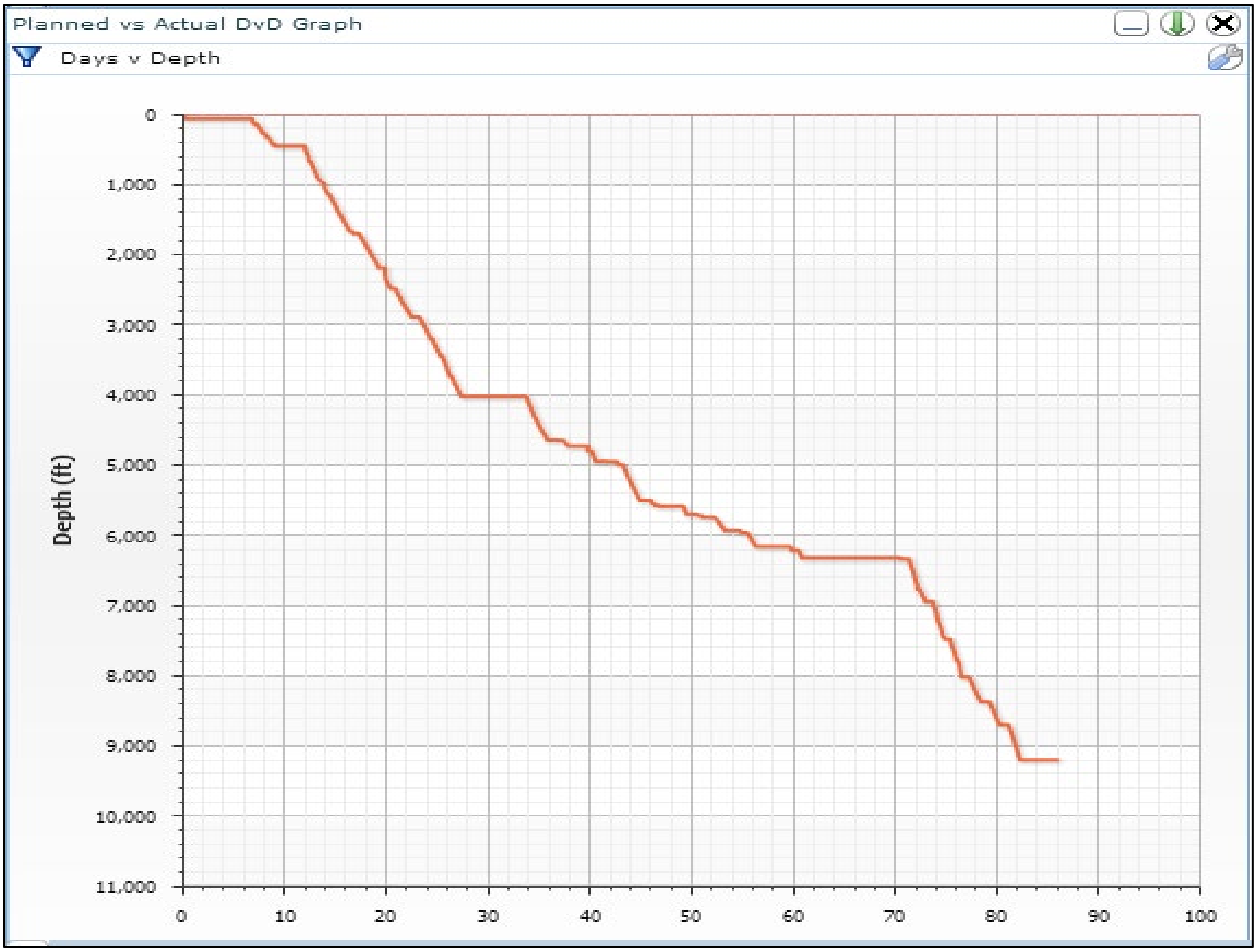

Figure 75: Geo Well #12; Days vs. Depth Drilled

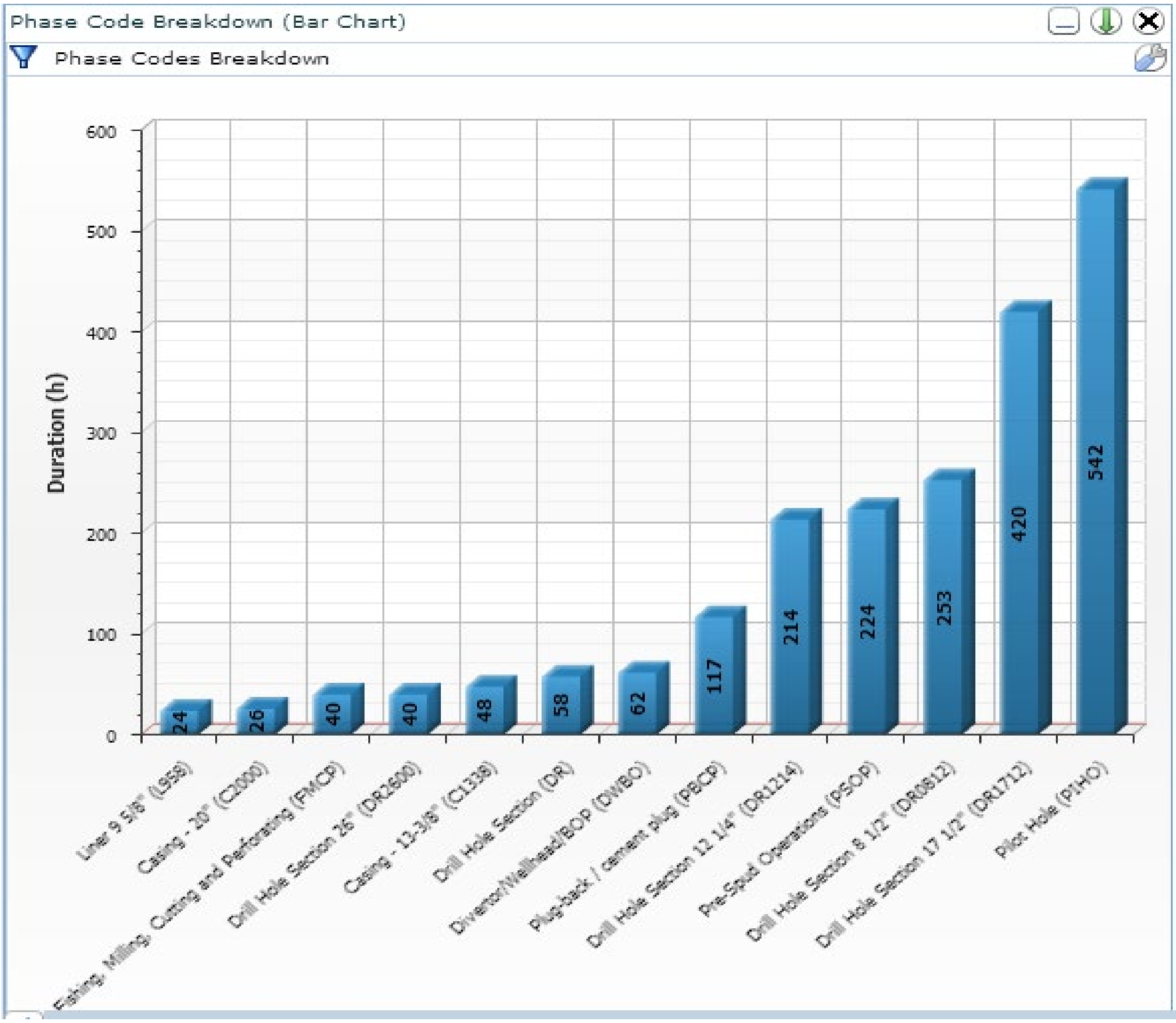

Figure 76: Geo Well #12; Phase Code Breakdown

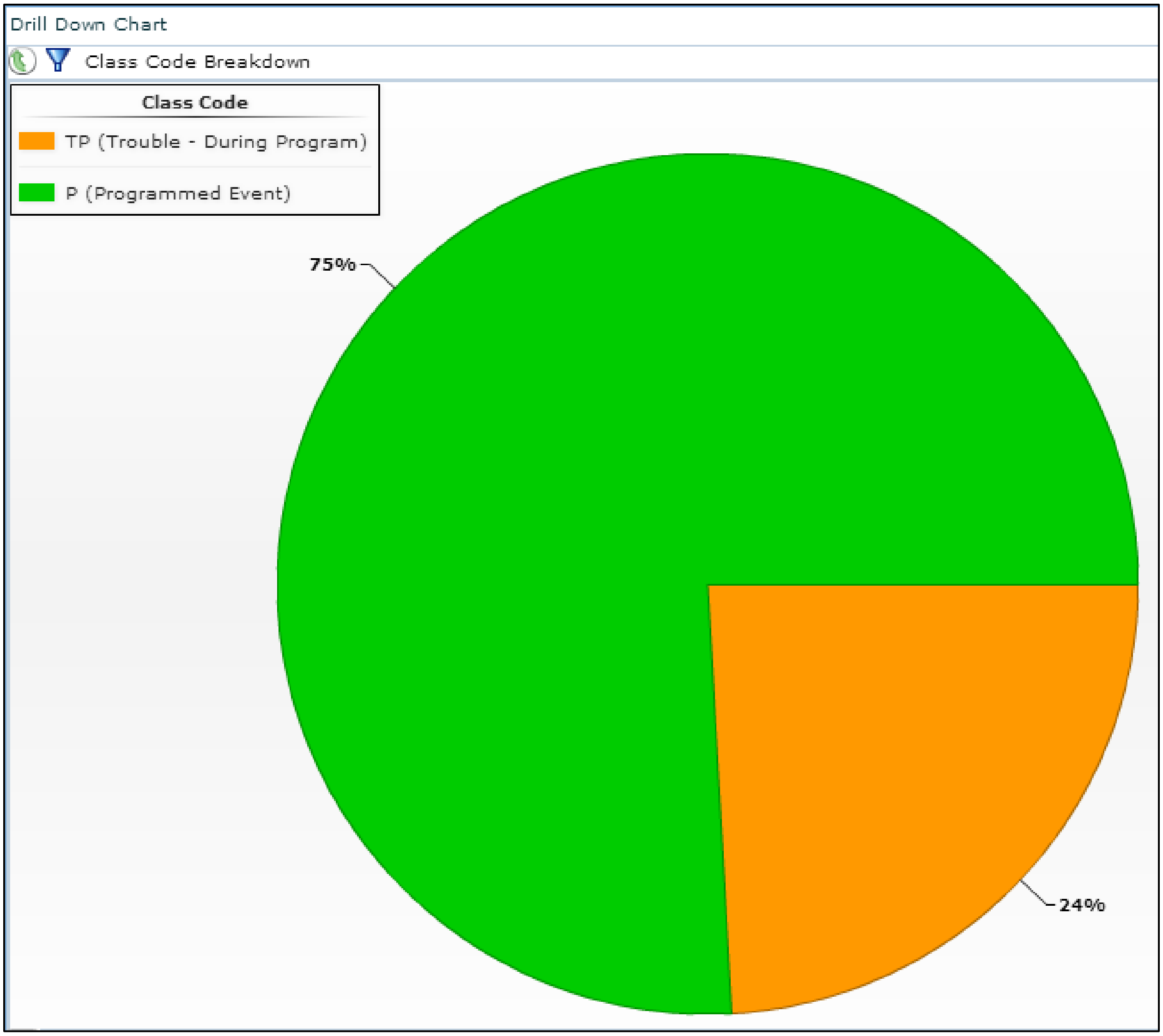

Figure 77: Geo Well #12; Percentage of Class Code Breakdowns

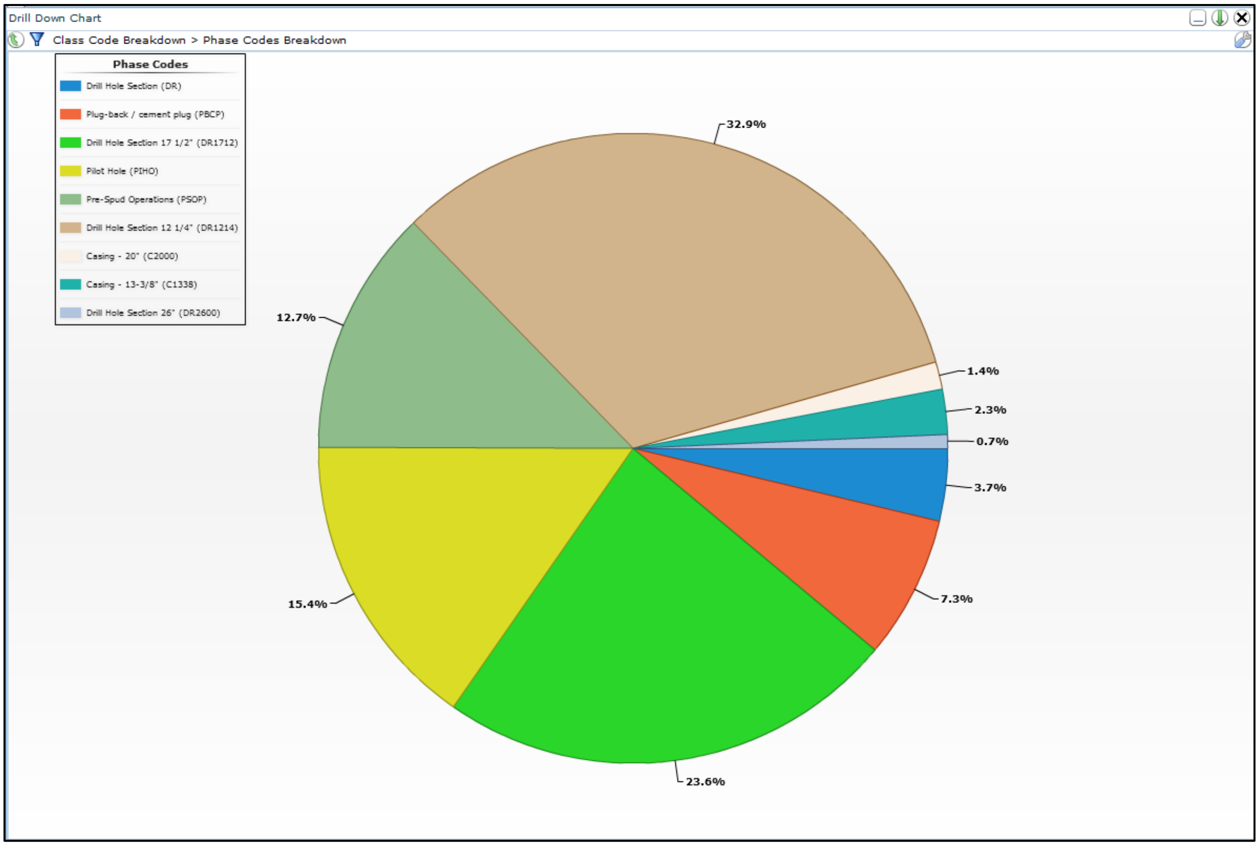

Figure 78: Geo Well #12; Percentage of Programmed Phase Code Breakdowns

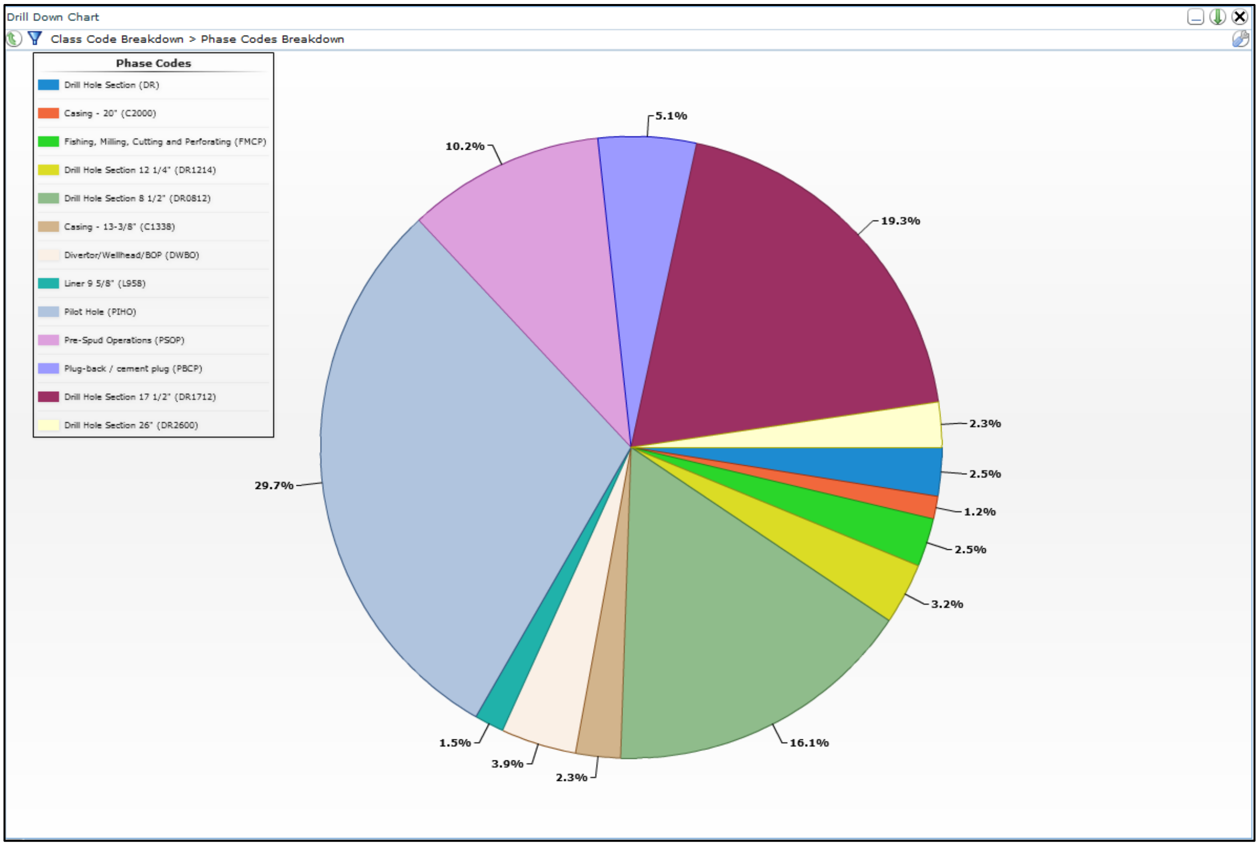

Figure 79: Geo Well #12; Percentage of Trouble during Programmed Code Breakdowns

Geo 13: DVD

No Viable Data Present

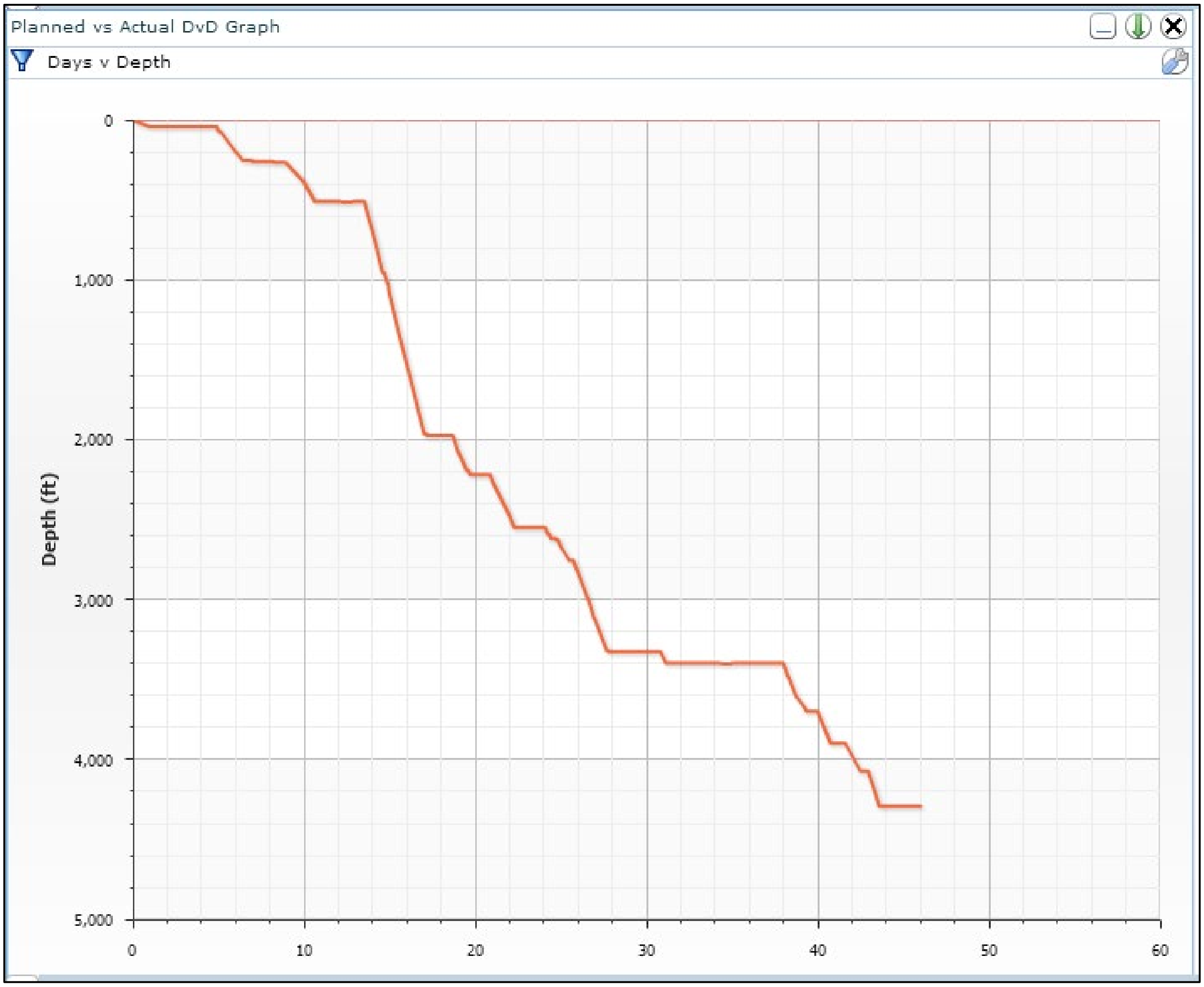

Figure 80: Geo Well #14; Days vs. Depth Drilled

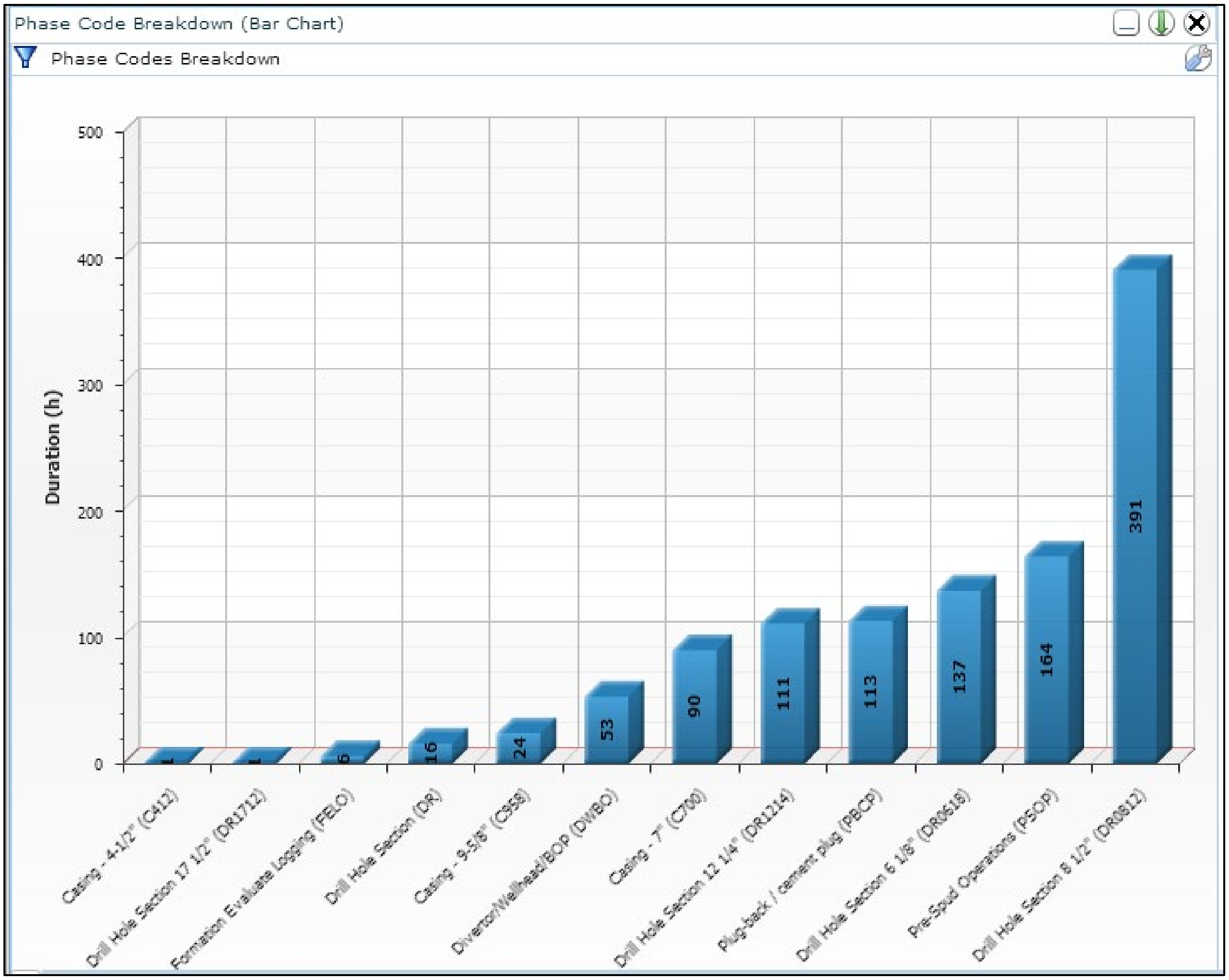

Figure 81: Geo Well #14; Phase Code Breakdown

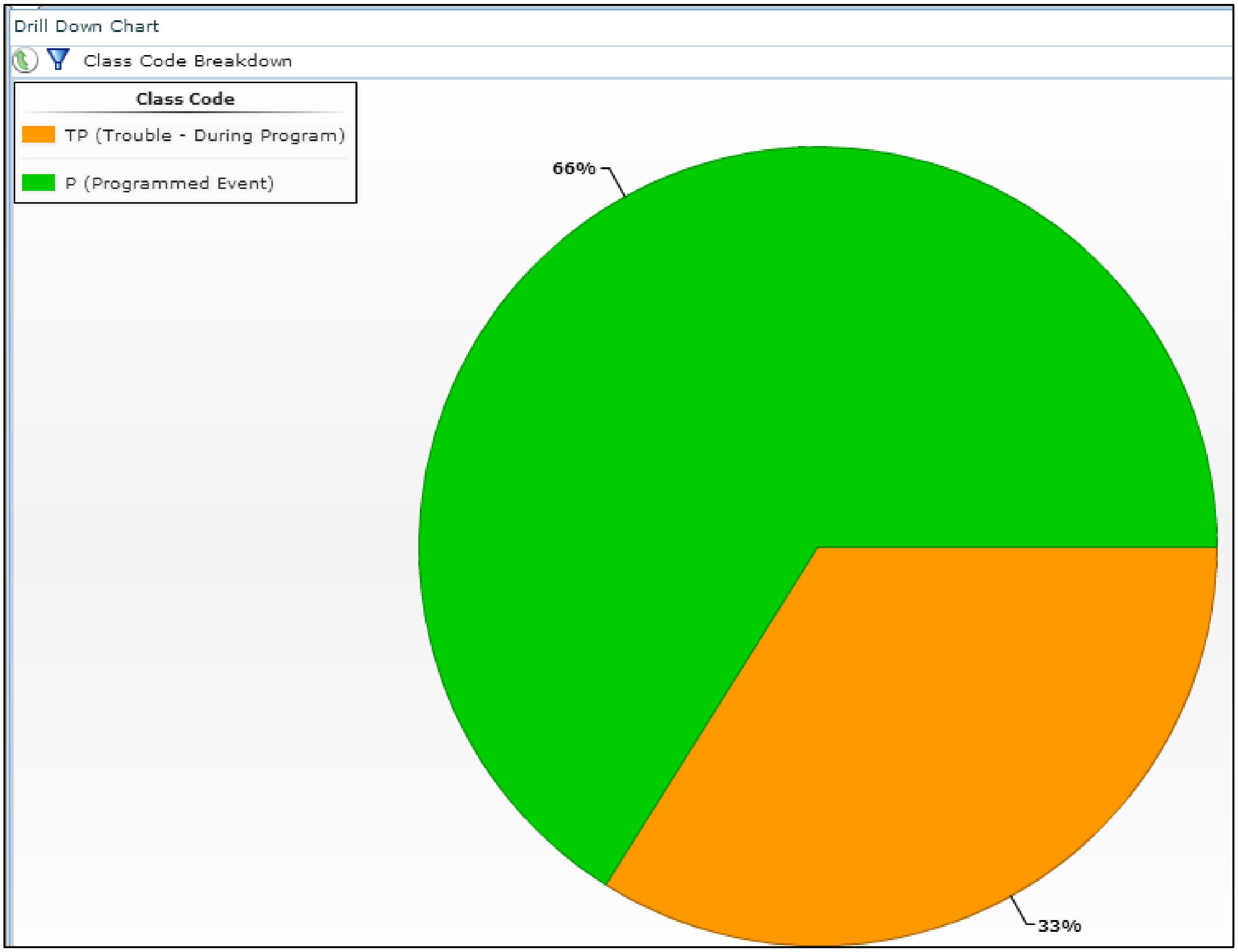

Figure 82: Geo Well #14; Percentage of Class Code Breakdowns

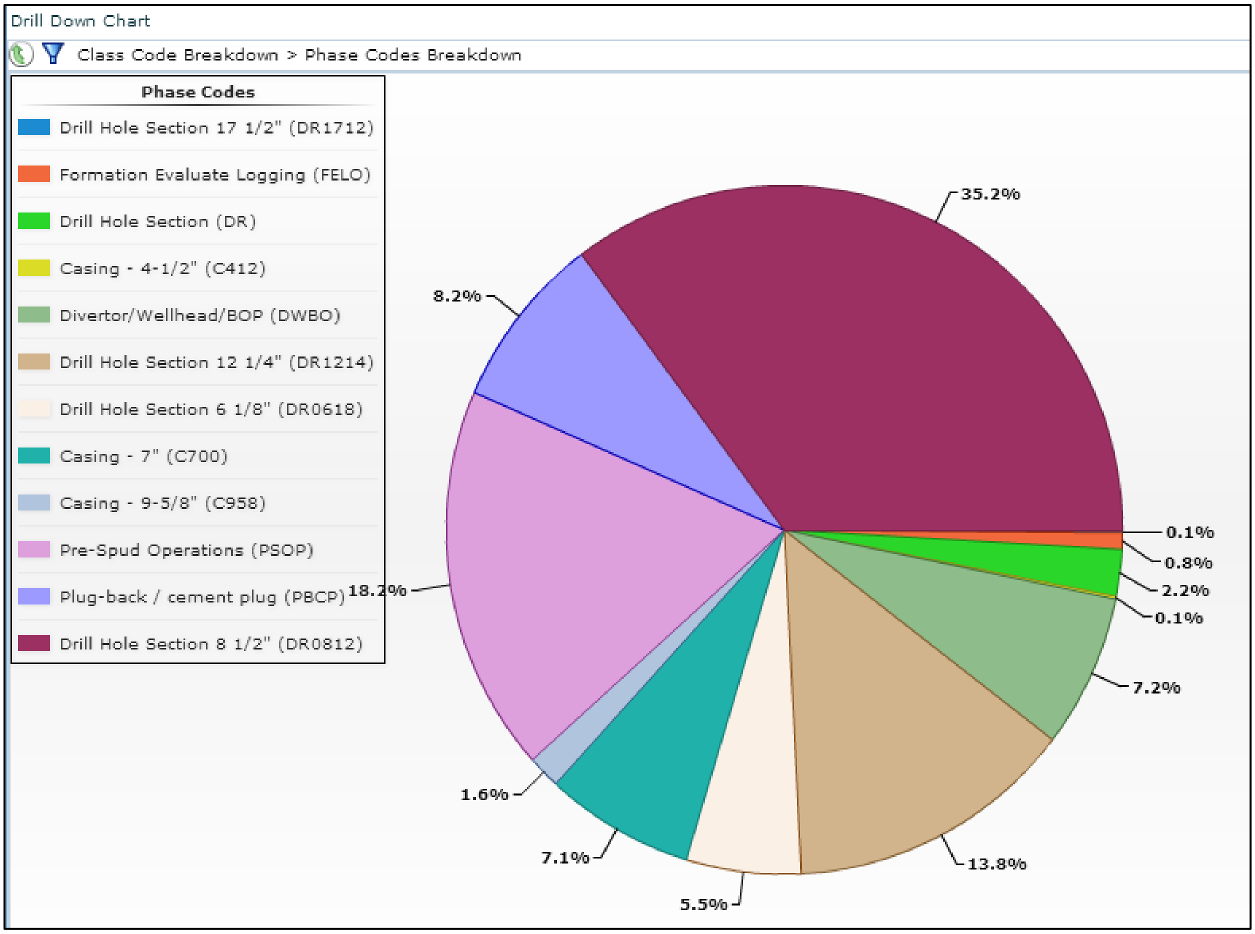

Figure 83: Geo Well #14; Percentage of Programmed Phase Code Breakdowns

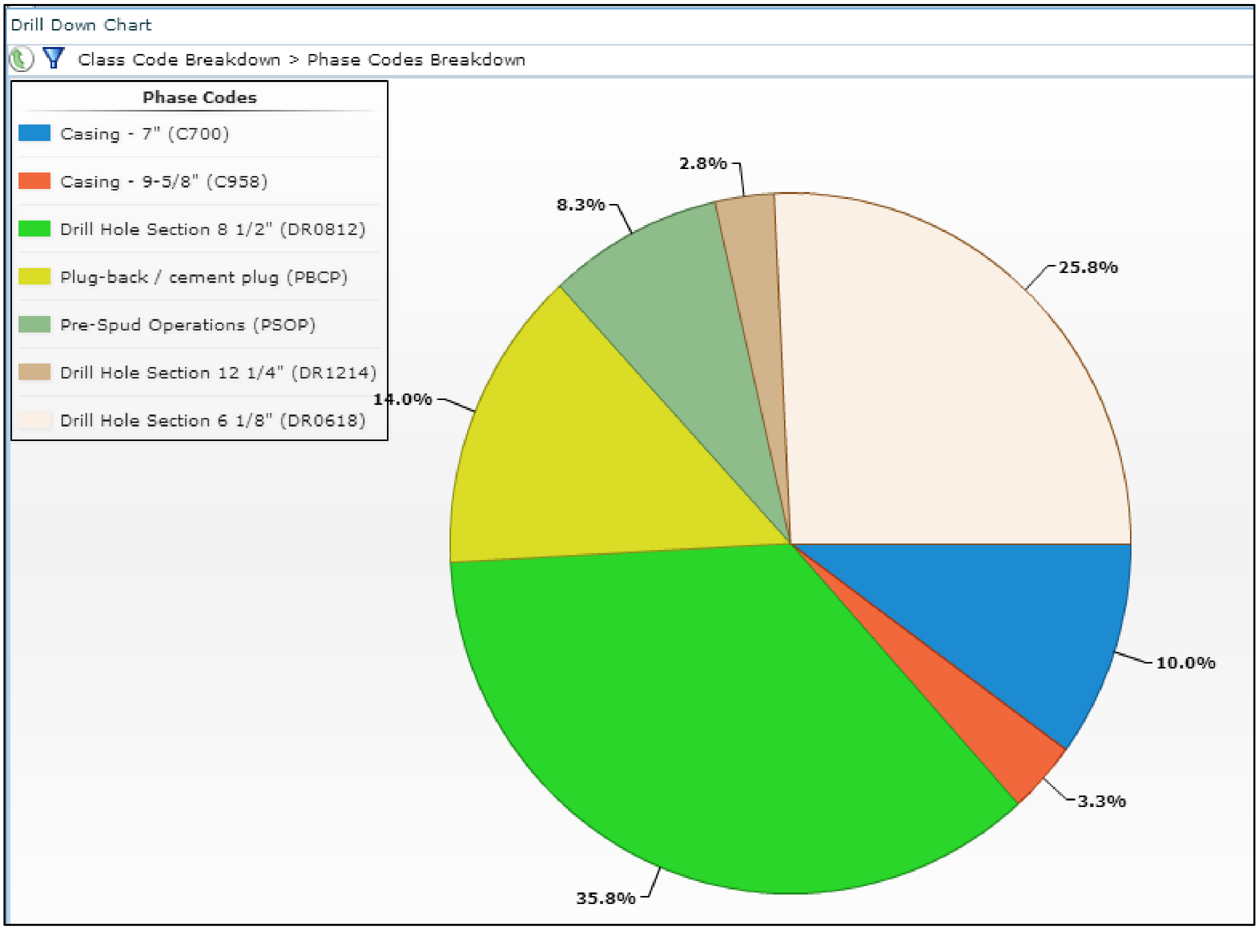

Figure 84: Geo Well #14; Percentage of Trouble during Phase Code Breakdown

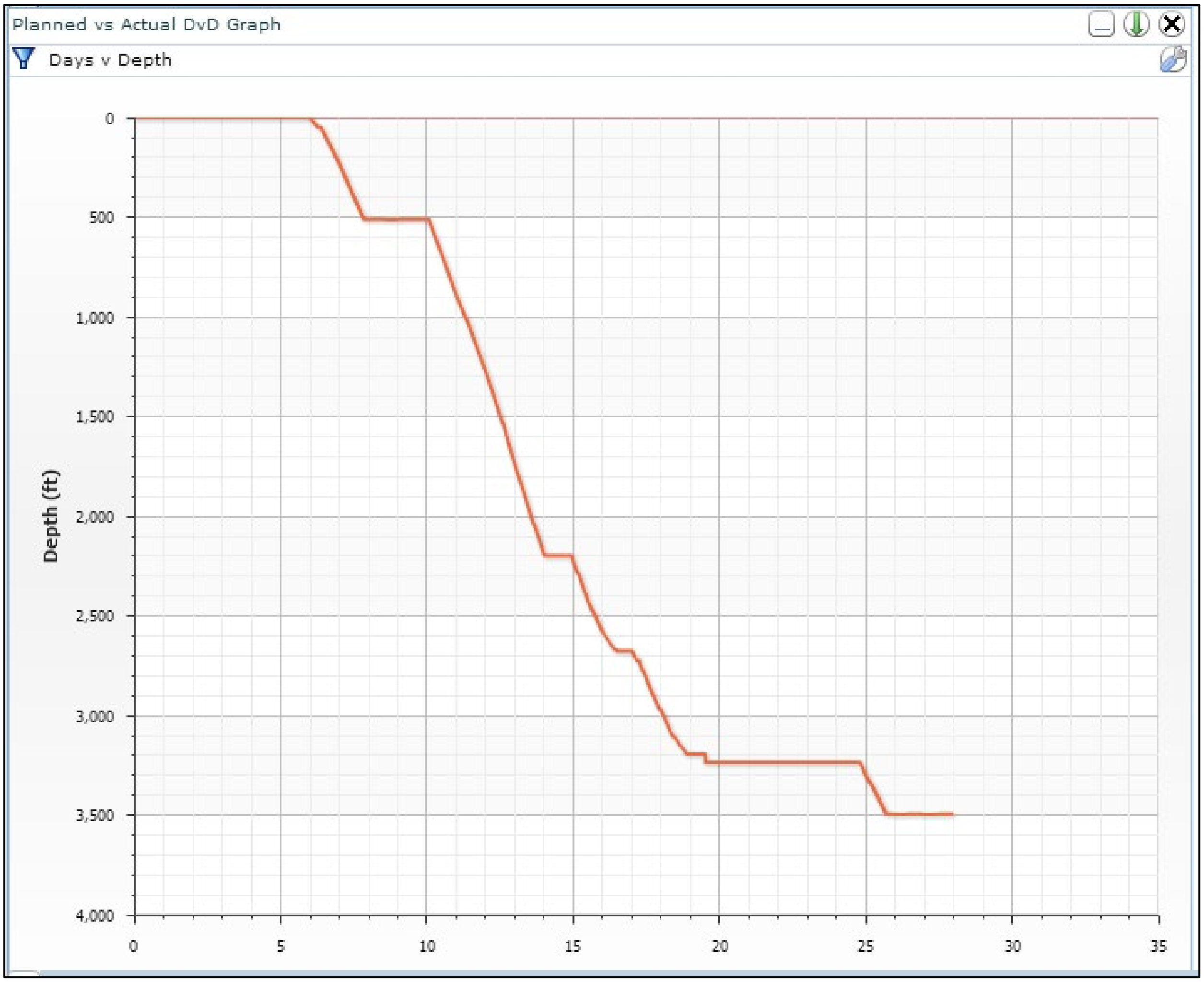

Figure 85: Geo Well #15; Days vs. Depth Drilled

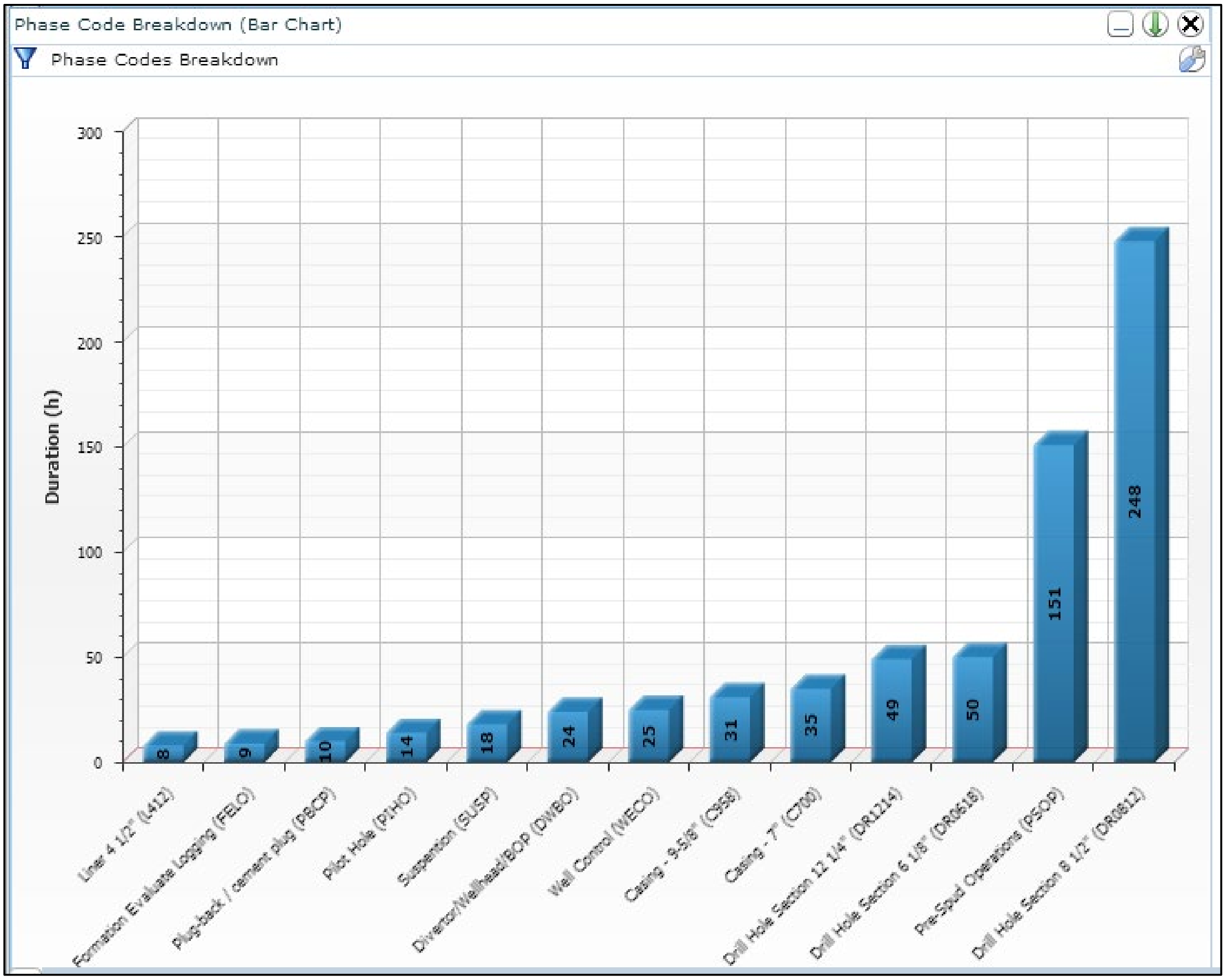

Figure 86: Geo Well #15; Phase Code Breakdown

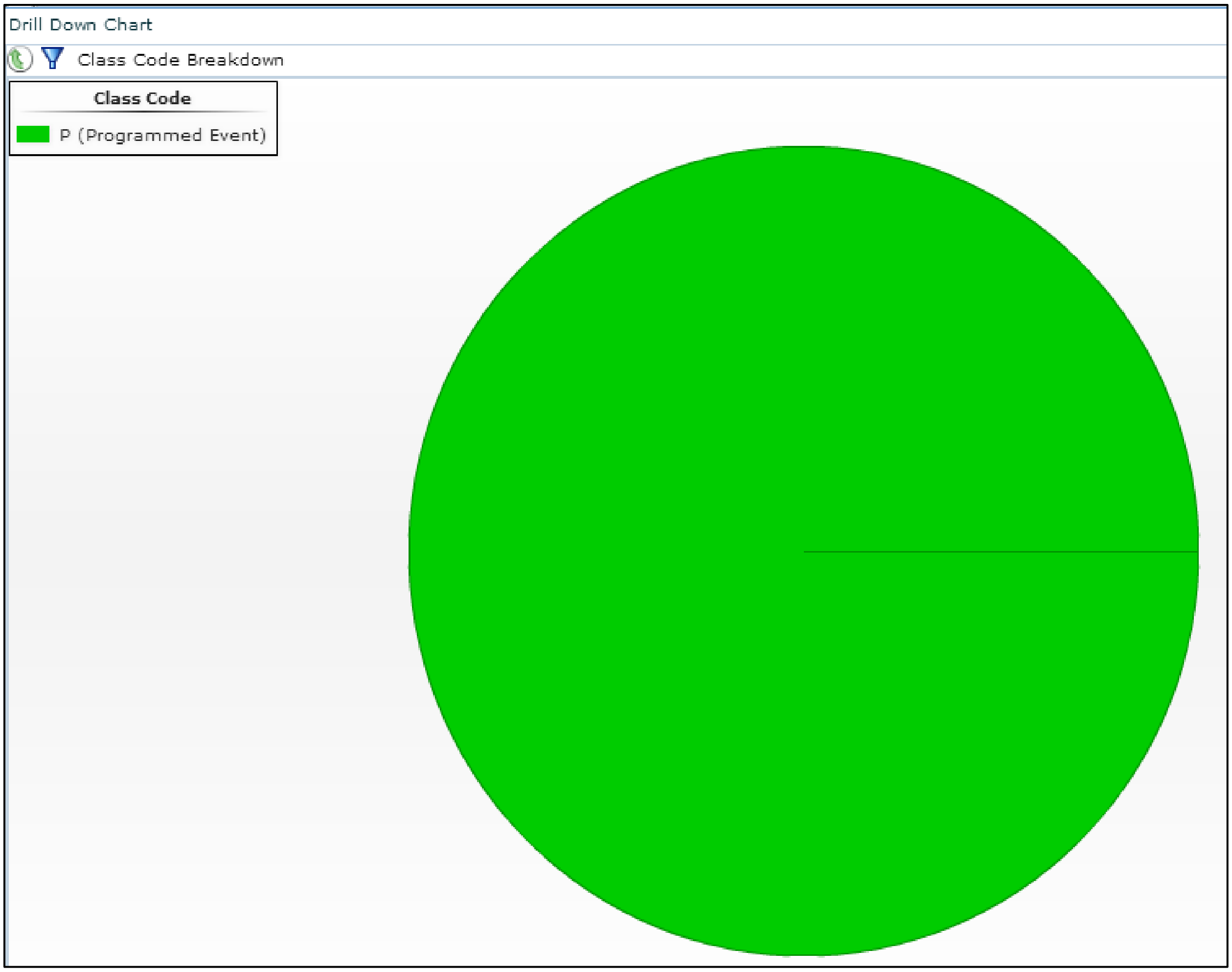

Figure 87: Geo Well #15; Percentage of Class Code Breakdowns

Geo 16 & 17

No Viable Data

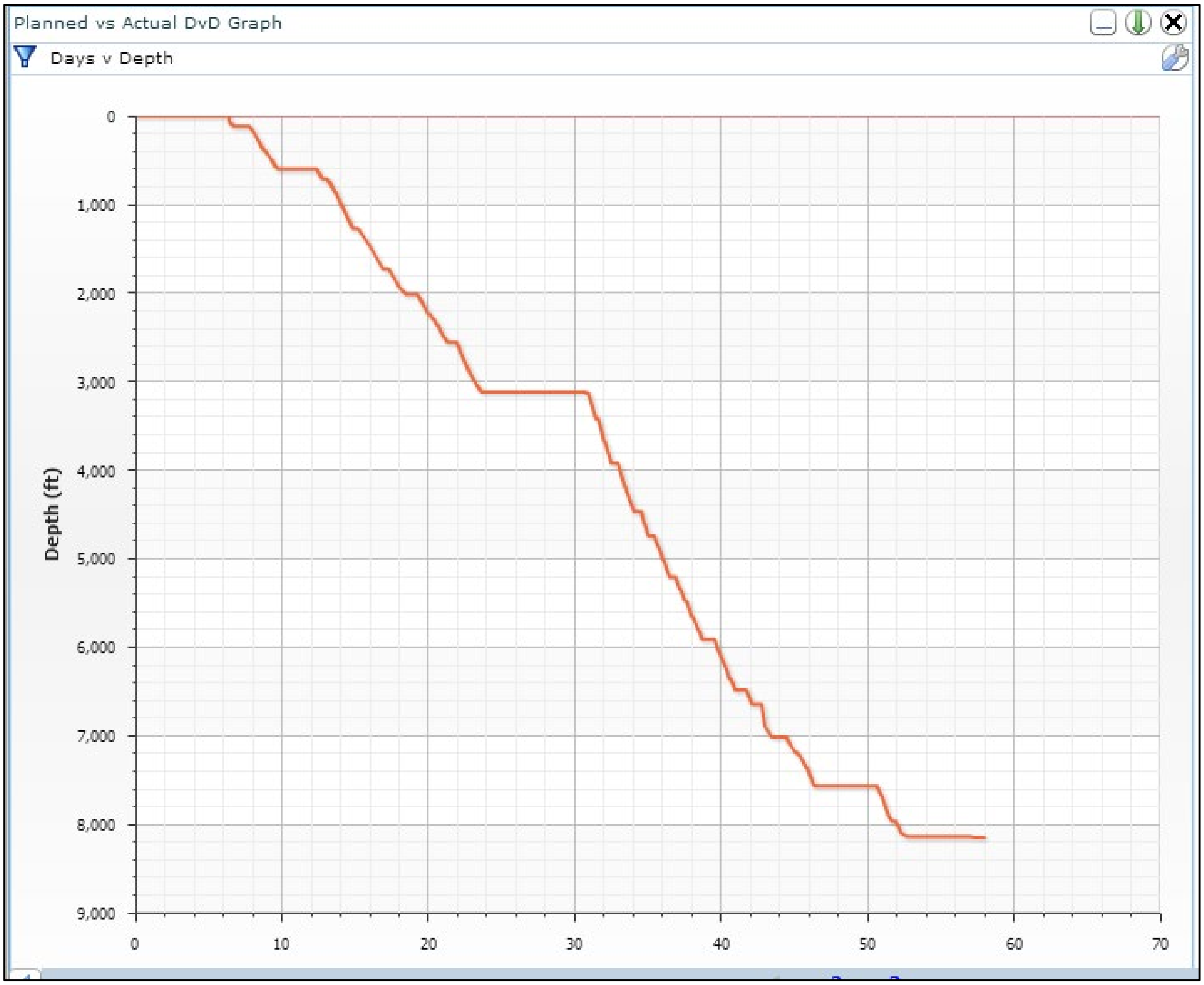

Figure 88: Geo Well #18; Days vs. Depth Drilled

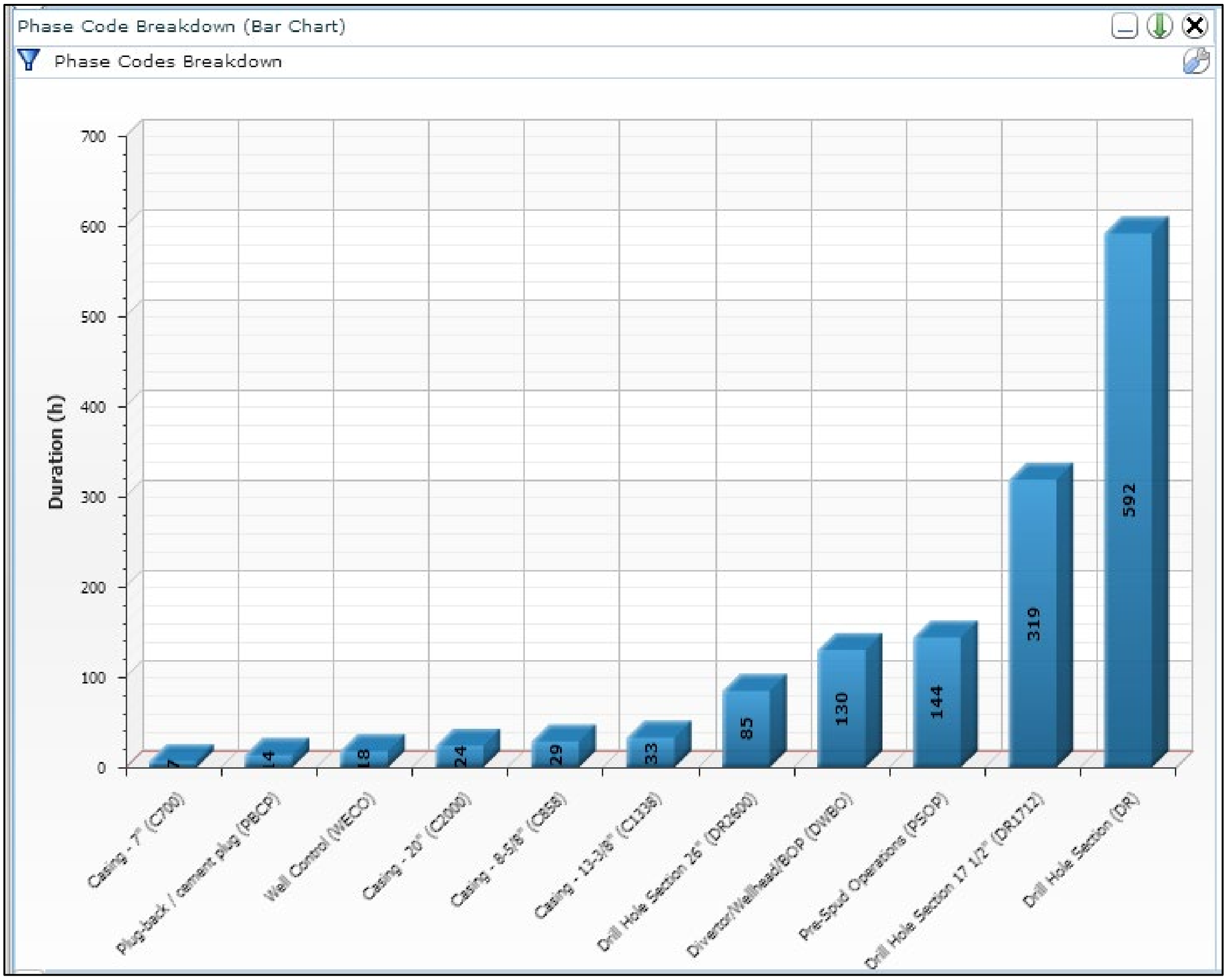

Figure 89: Geo Well #18; Phase Code Breakdown

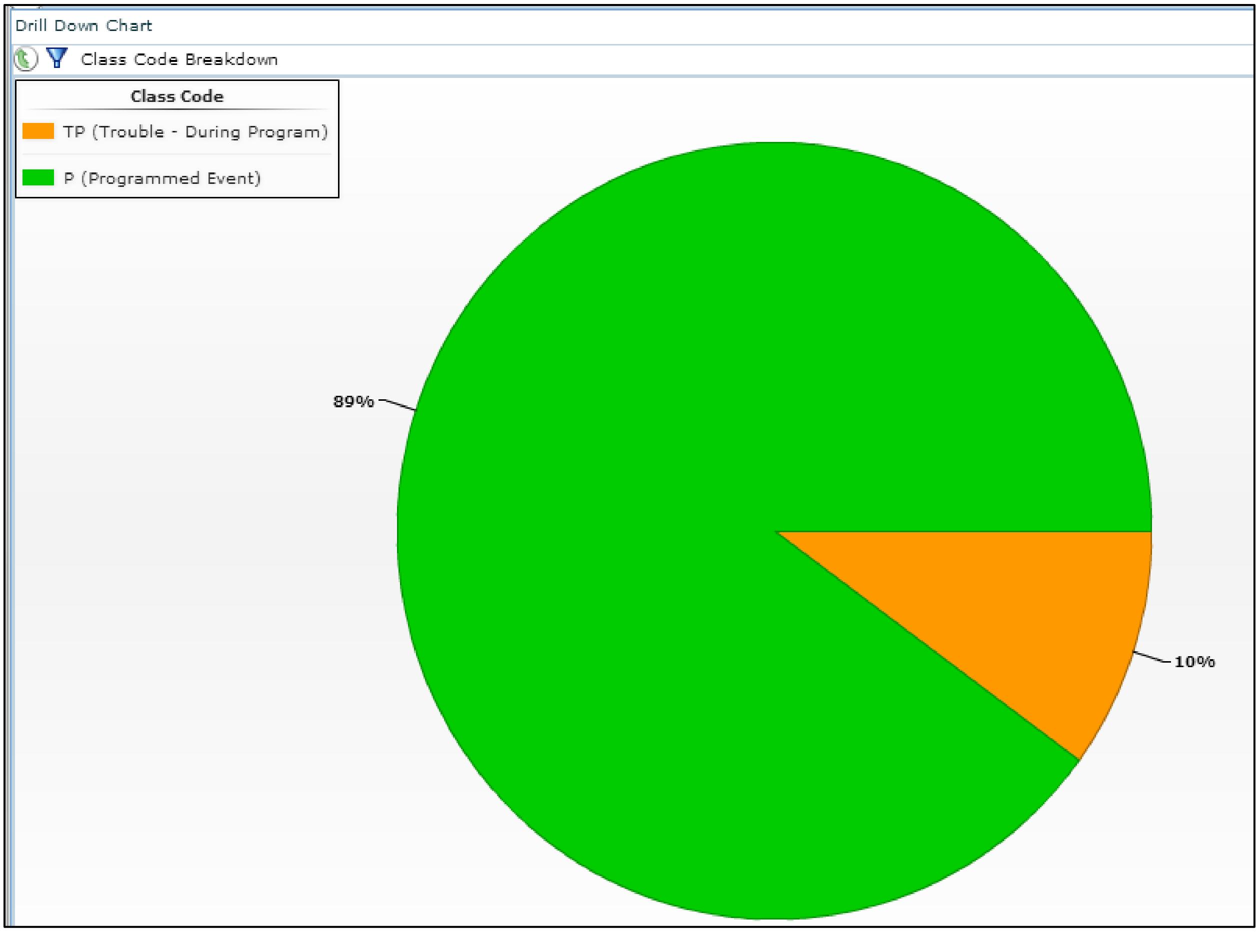

Figure 90: Geo Well #18; Percentage of Class Code Breakdowns

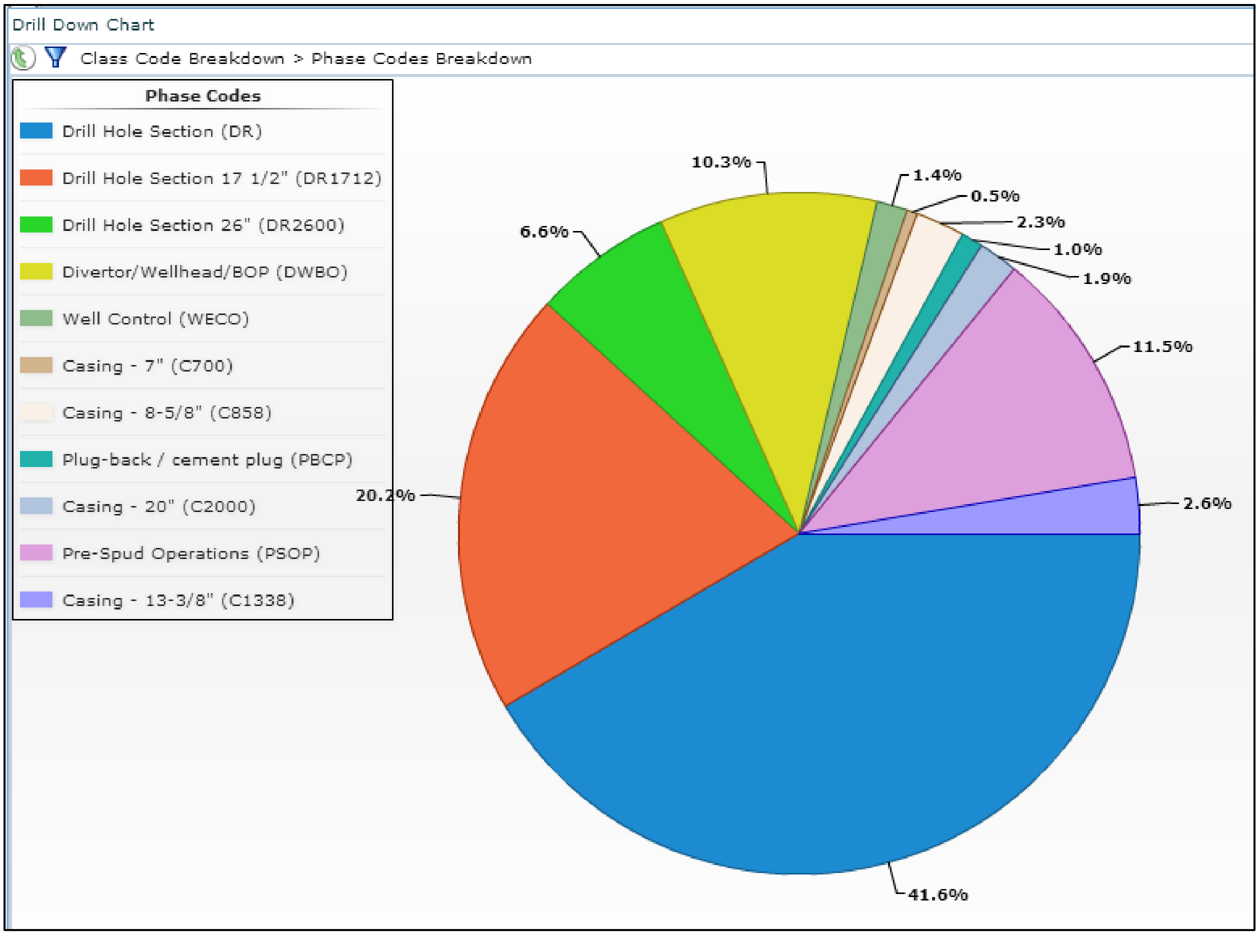

Figure 91: Geo Well #18; Percentage of Programmed Phase Code Breakdowns

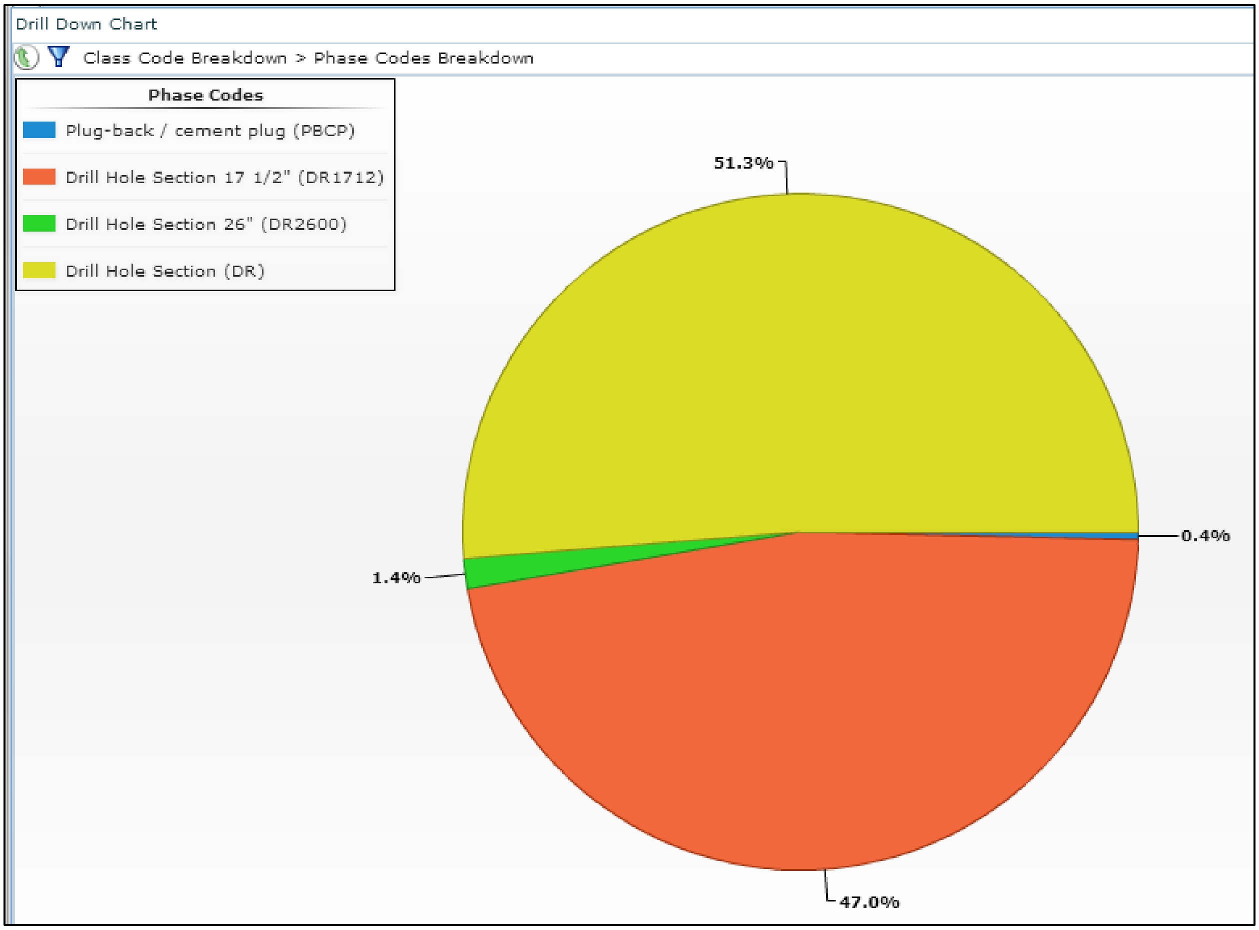

Figure 92: Geo Well #18; Percentage of Trouble during Programmed Phase Code Breakdowns

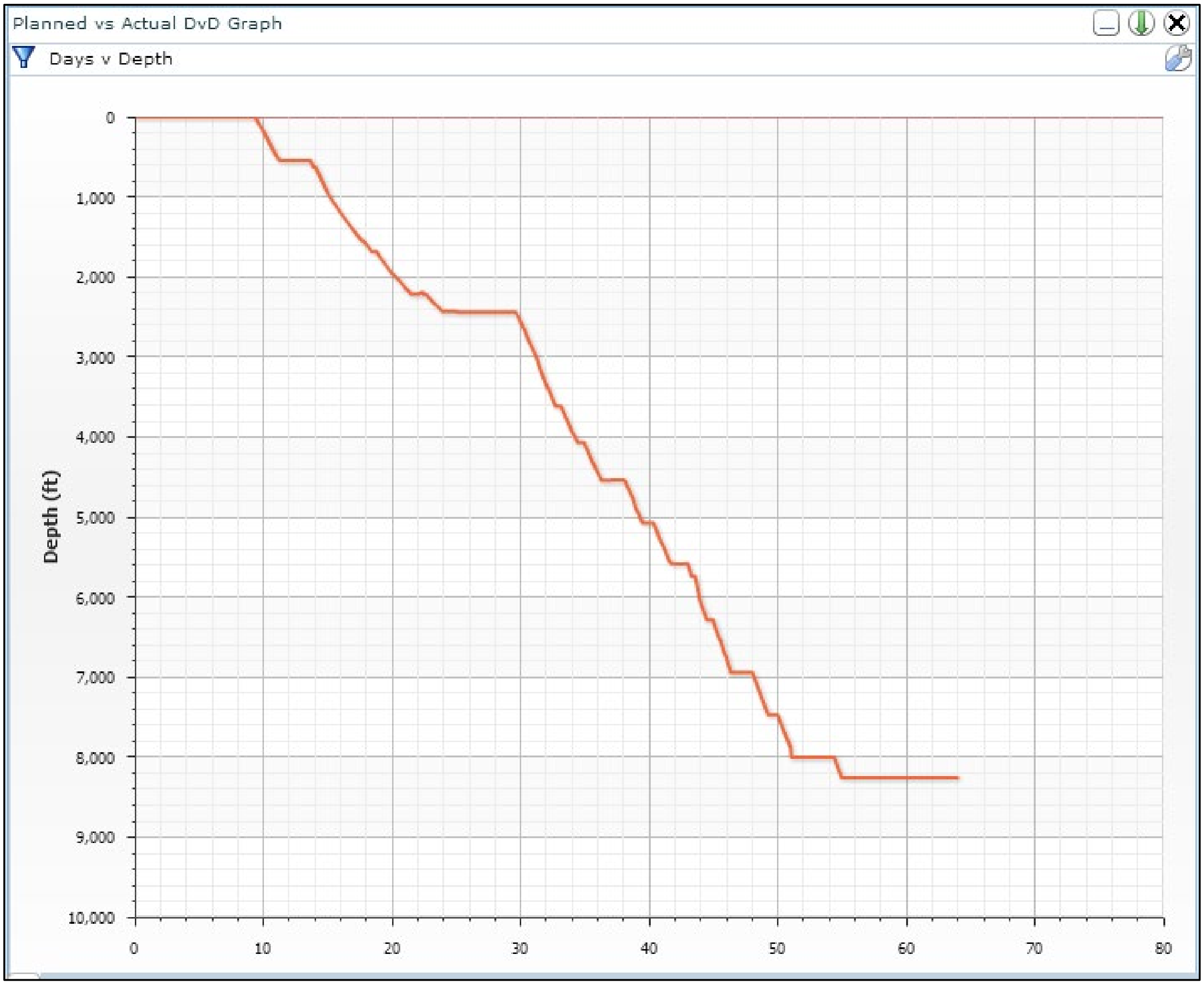

Figure 93: Geo Well #19; Days vs. Depth Drilled

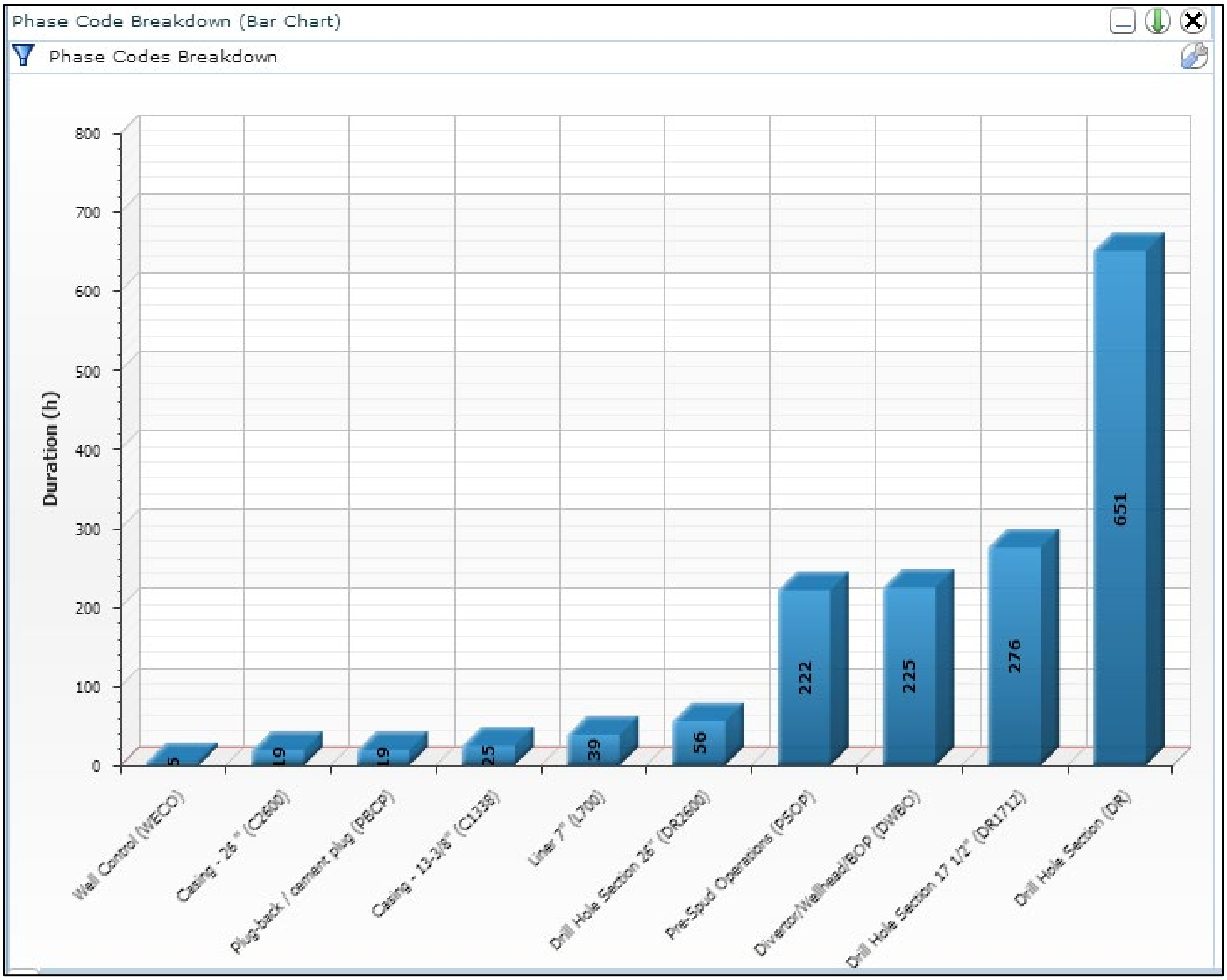

Figure 94: Geo Well #19; Phase Code Breakdown

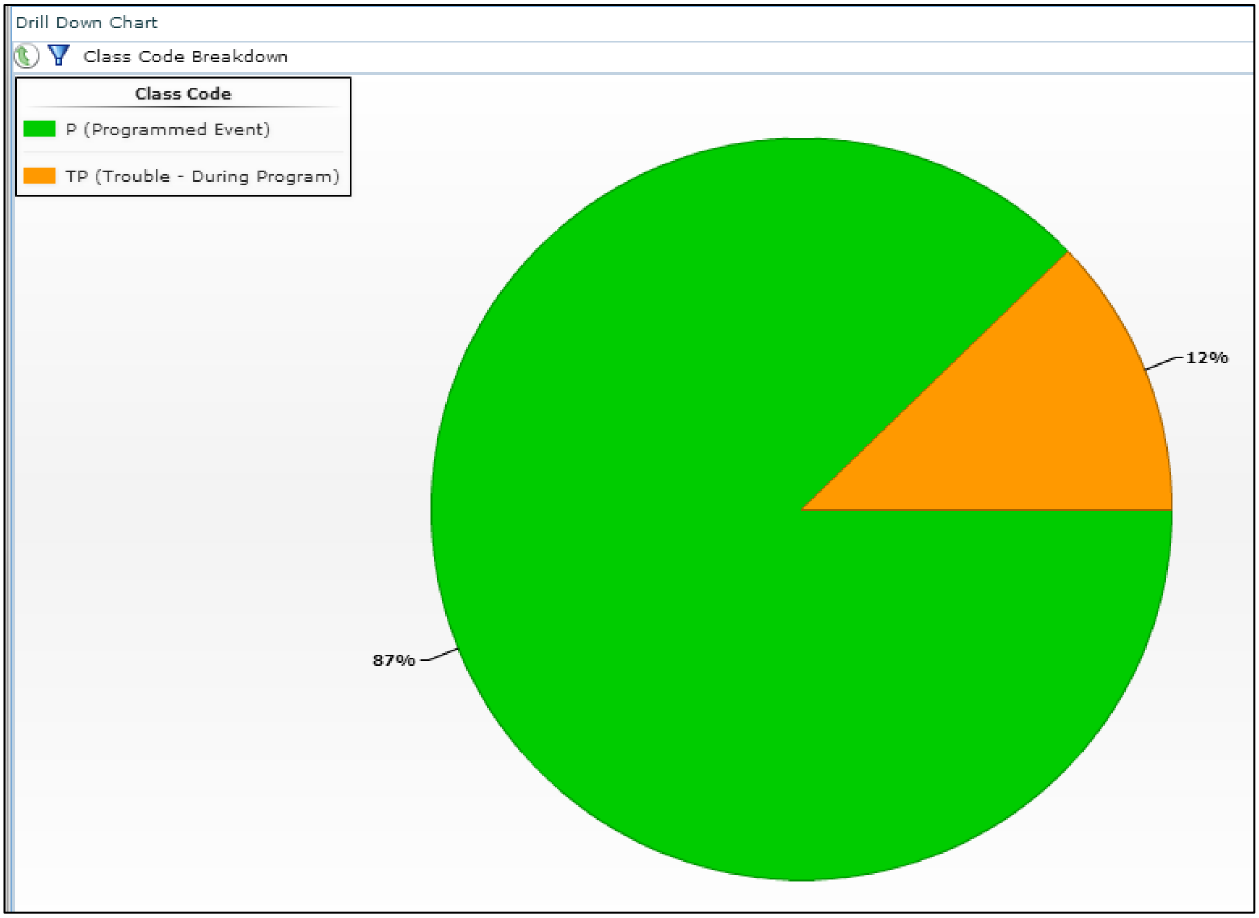

Figure 95: Geo Well #19; Percentage of Class Code Breakdown

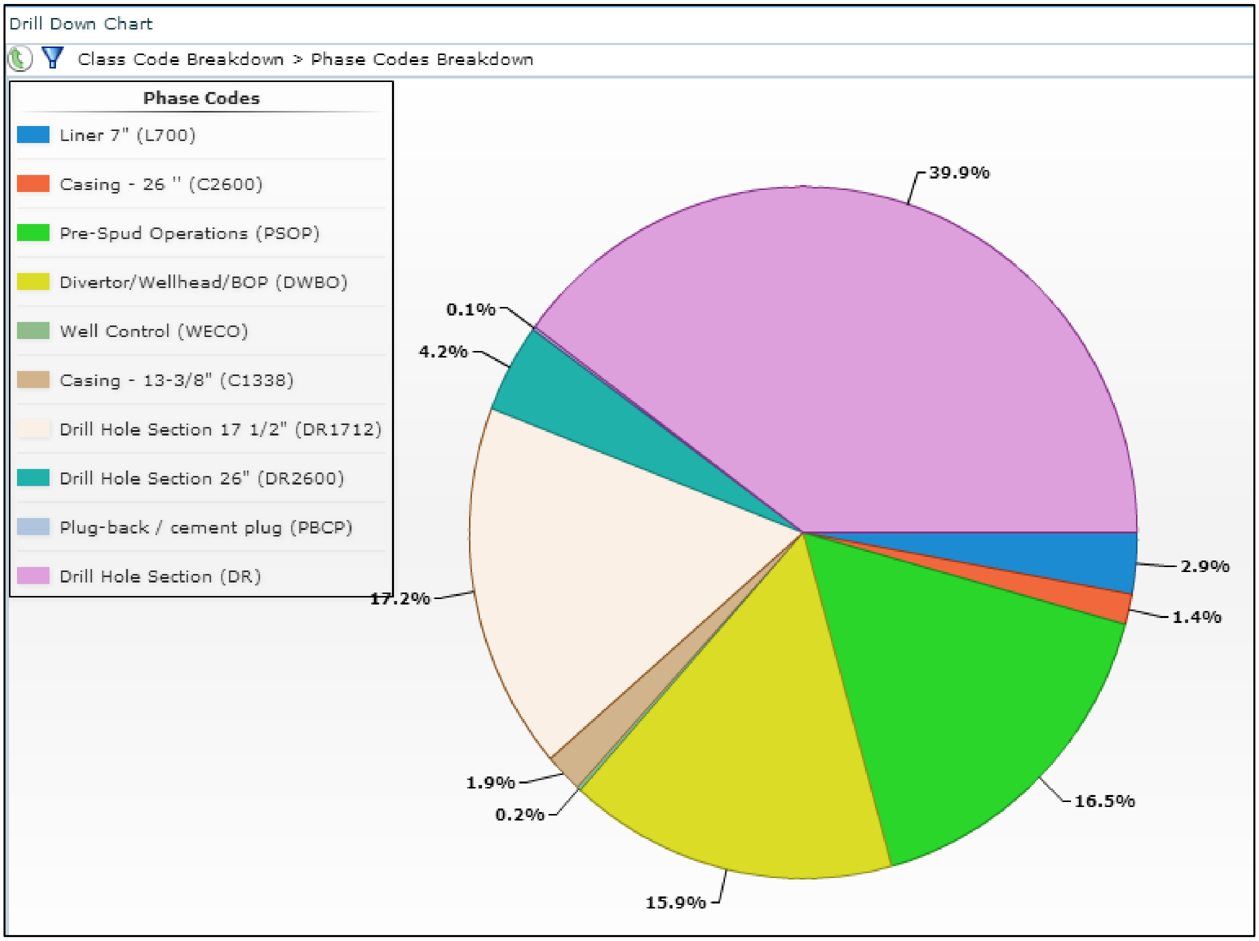

Figure 96: Geo Well #19; Percentage of Programmed Phase Code Breakdowns

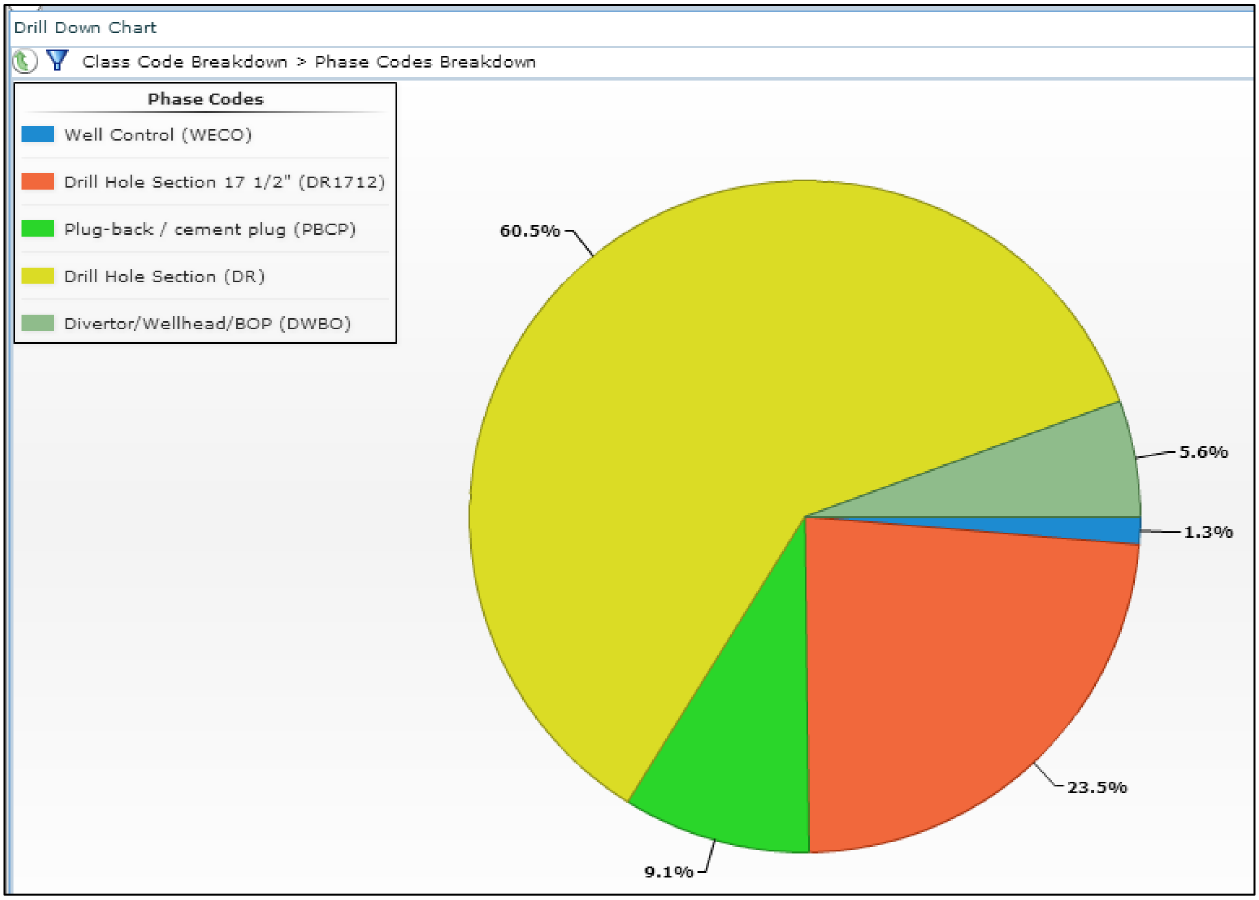

Figure 97: Geo Well #19; Percentage of Trouble during Programmed Phase Code Breakdowns

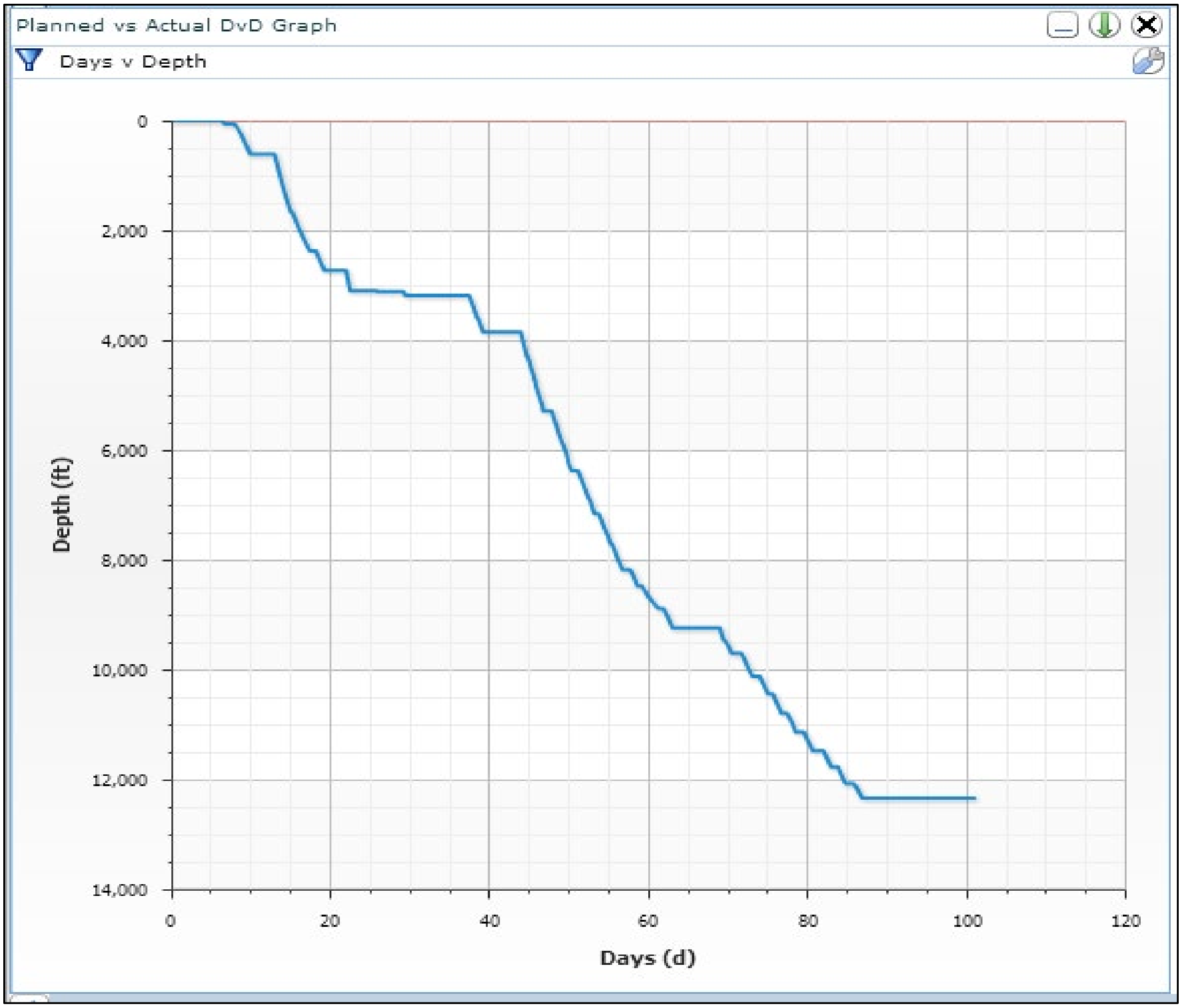

Figure 98: Geo Well #20; Days vs. Depth Drilled

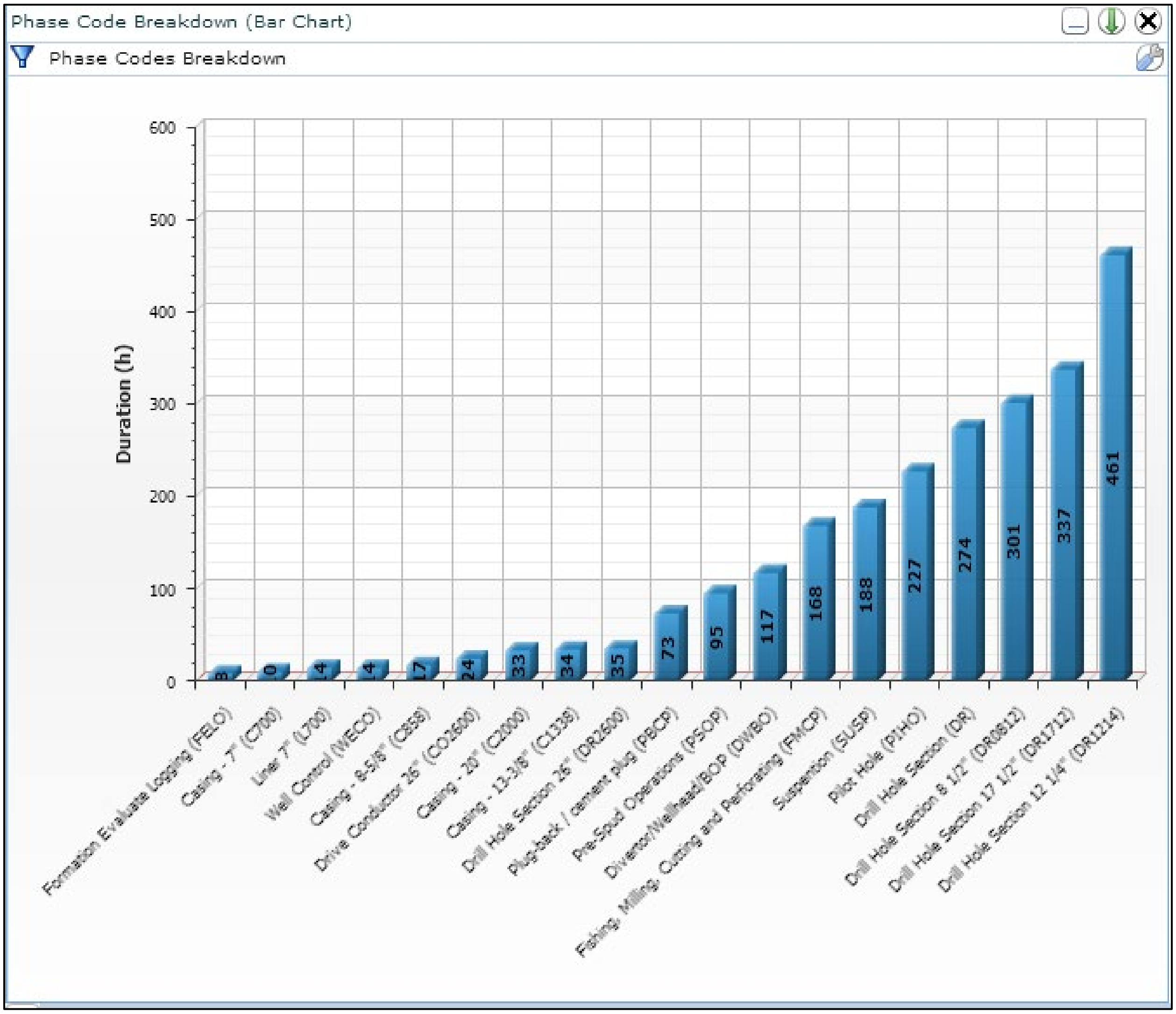

Figure 99: Geo Well #20; Phase Code Breakdown

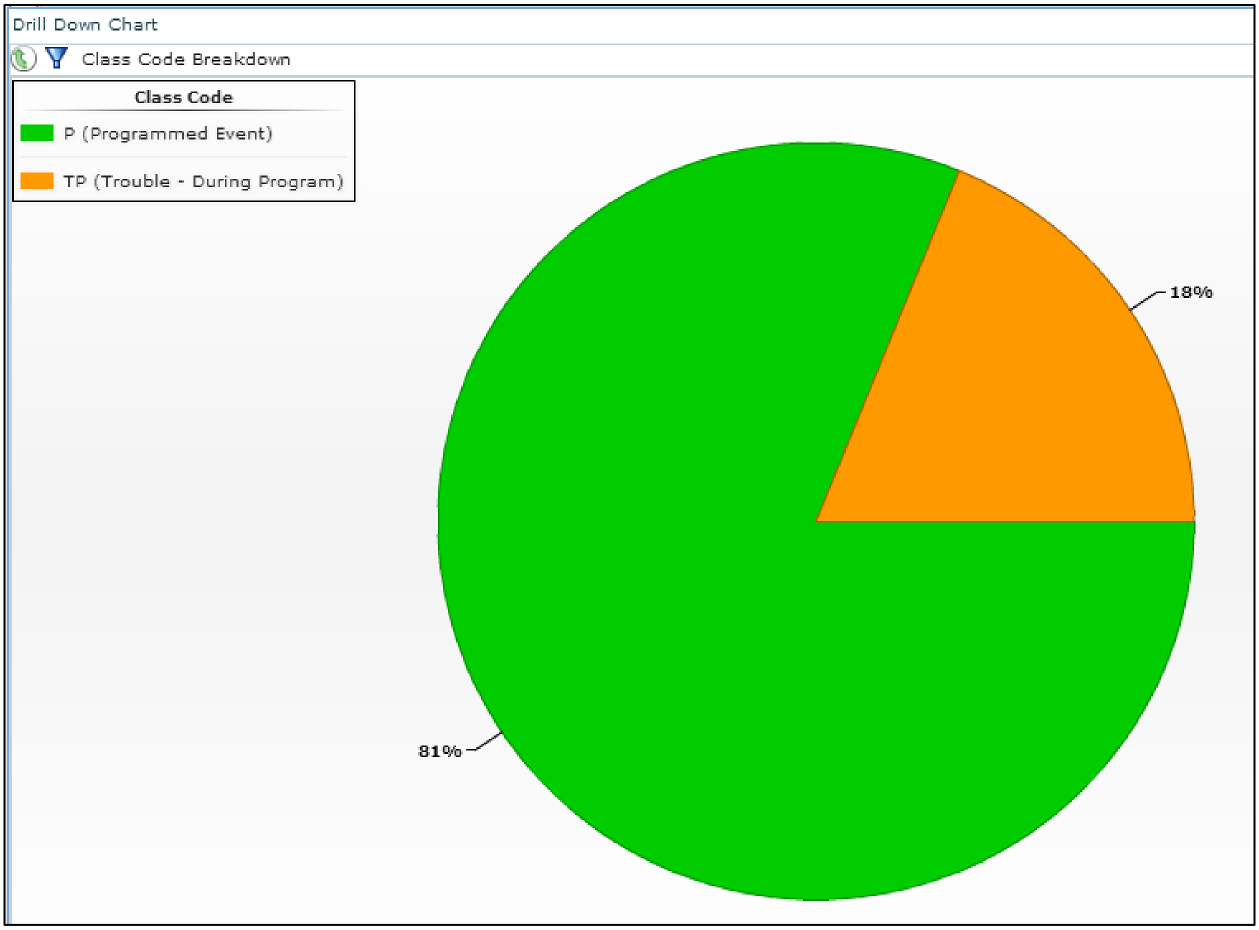

Figure 100: Geo Well #20; Percentage of Class Code Breakdowns

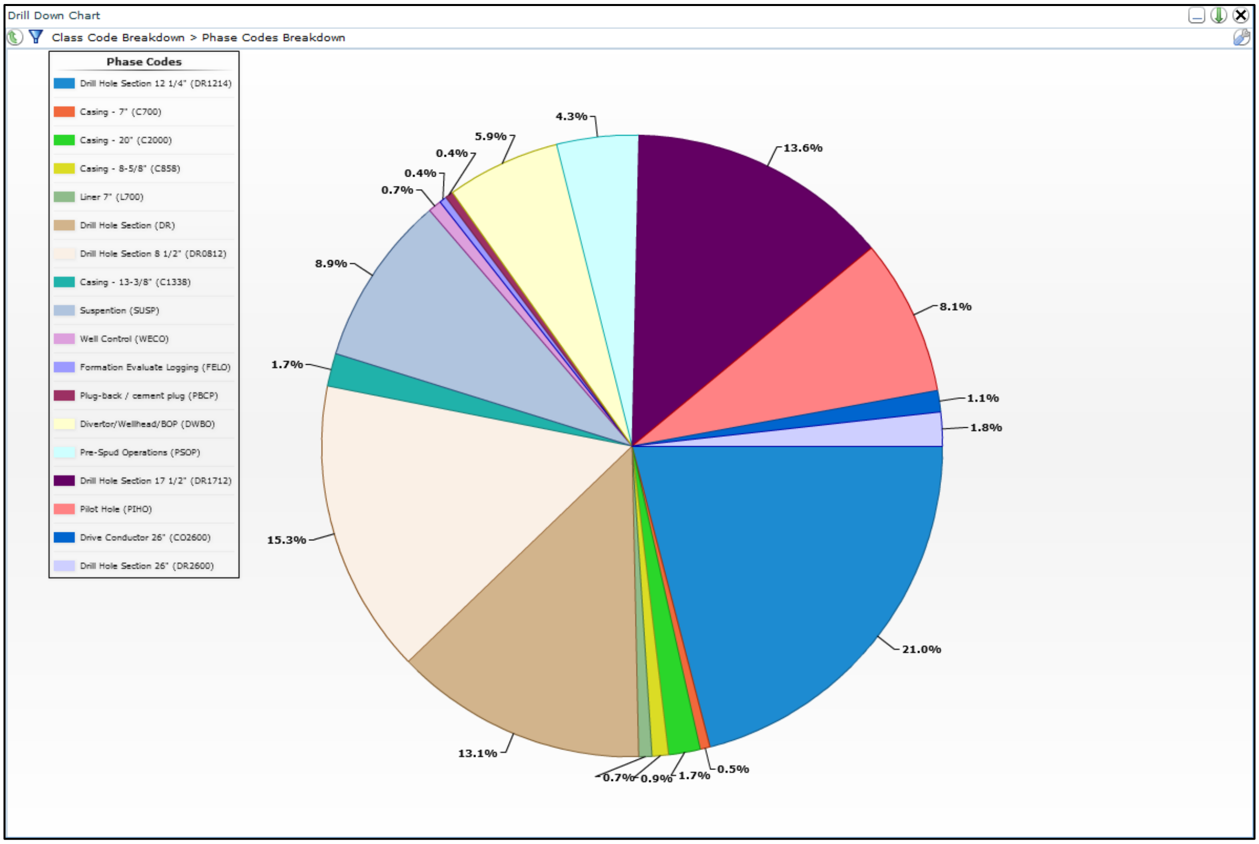

Figure 101: Geo Well #20; Percentage of Programmed Phase Code Breakdowns

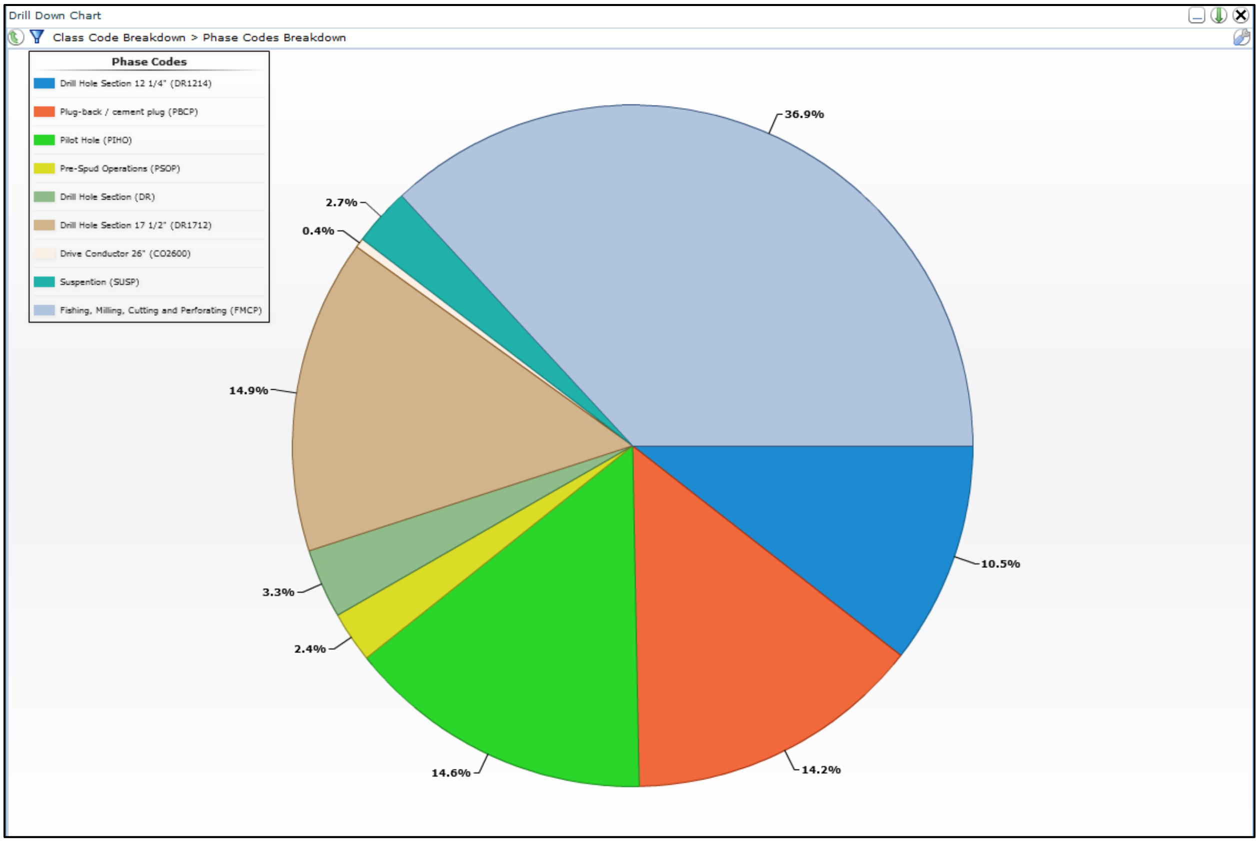

Figure 102: Geo Well #20; Percentage of Trouble during Programmed Phase Code Breakdowns

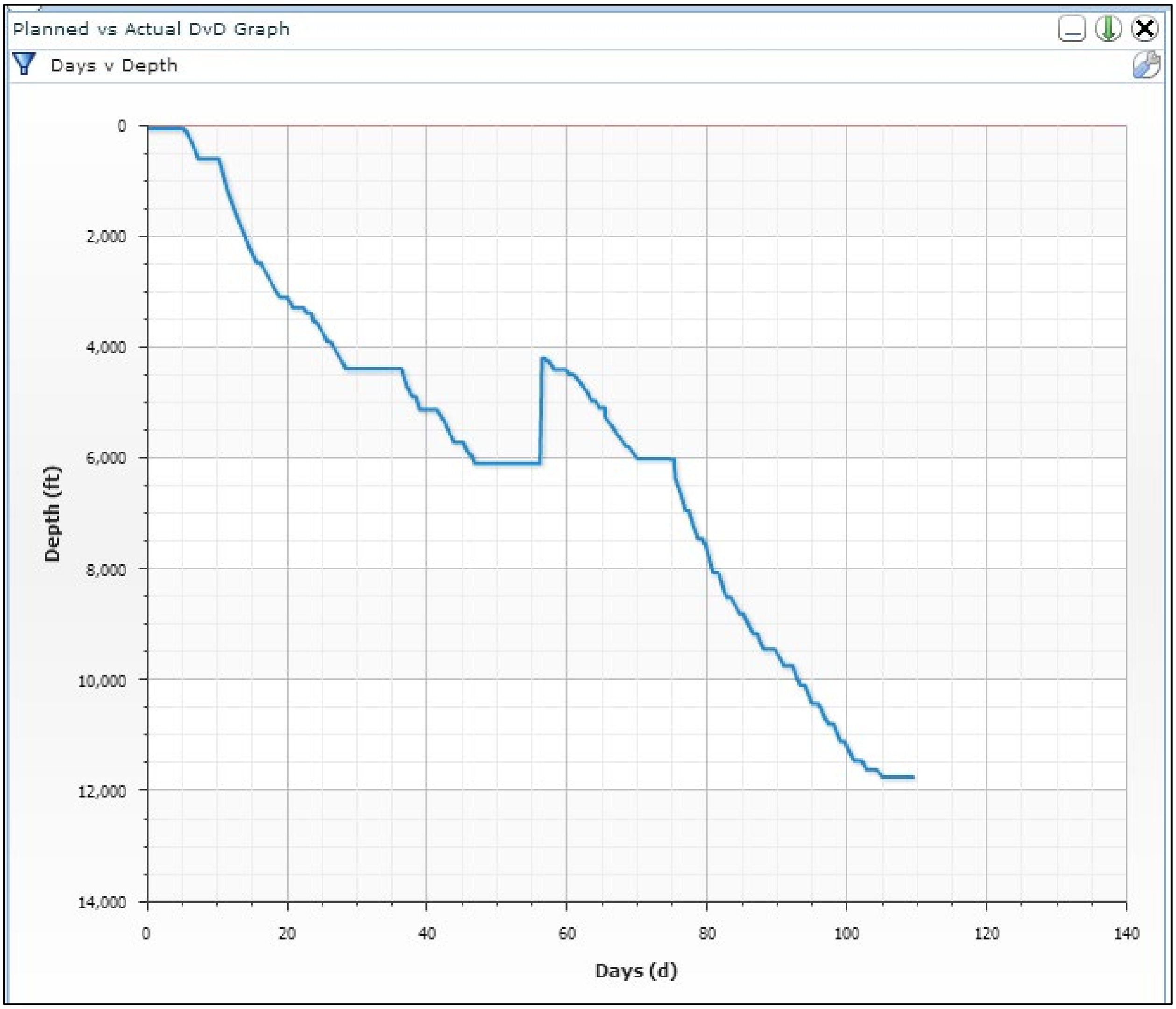

Figure 103: Geo Well #21; Days vs. Depth Drilled

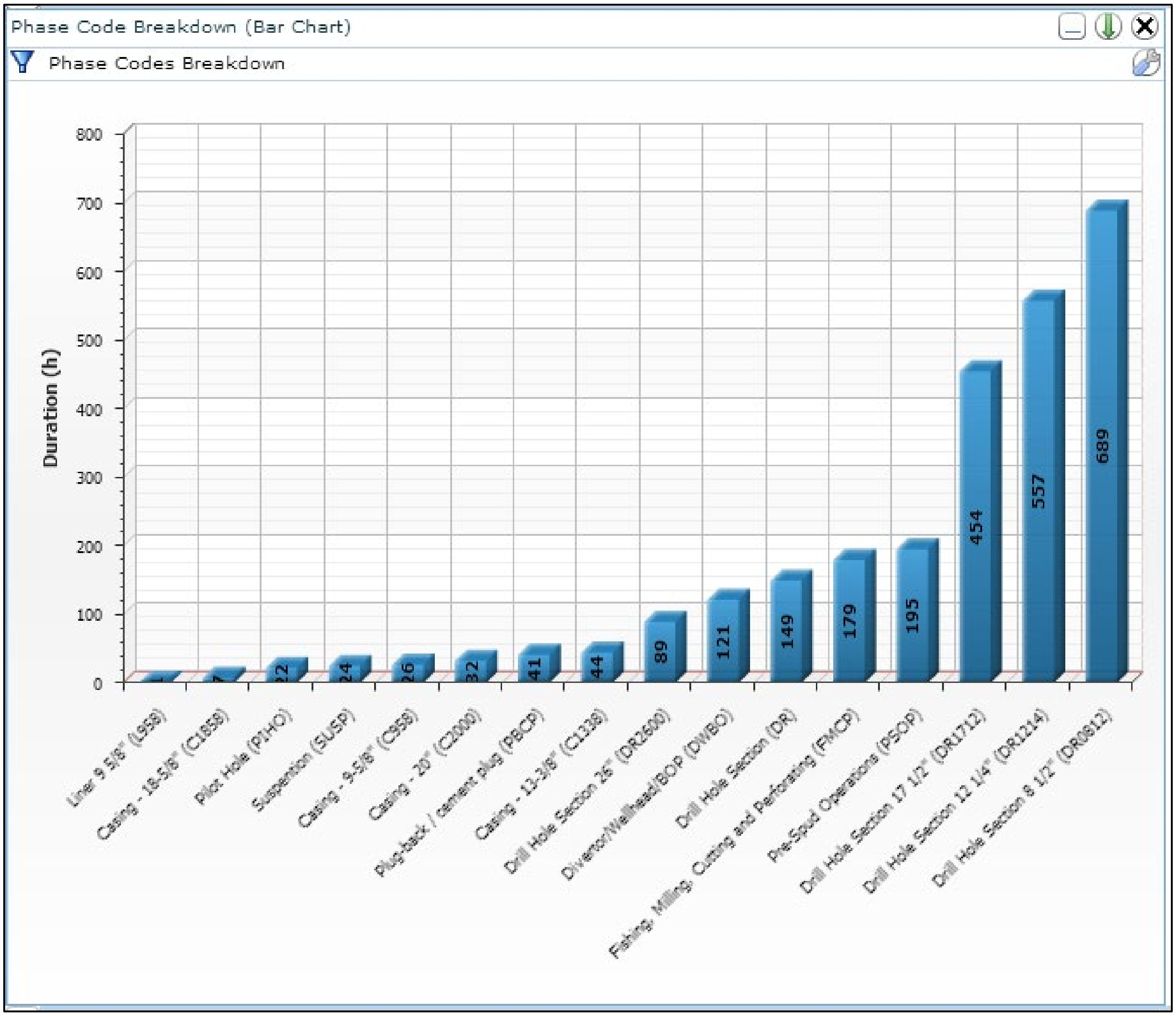

Figure 104: Geo Well #21; Phase code Breakdown

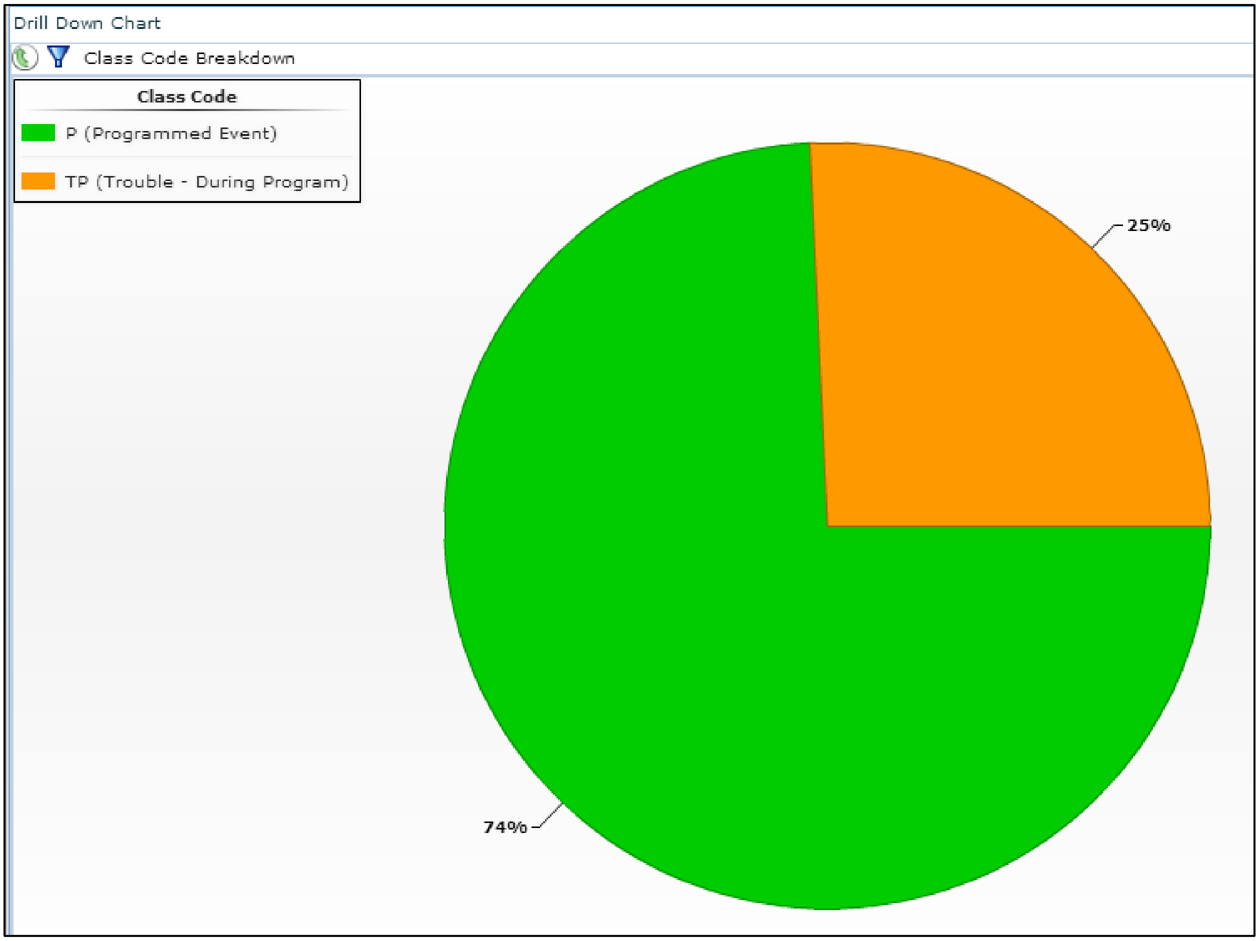

Figure 105: Geo Well #21; Percentage of Class Code Breakdown

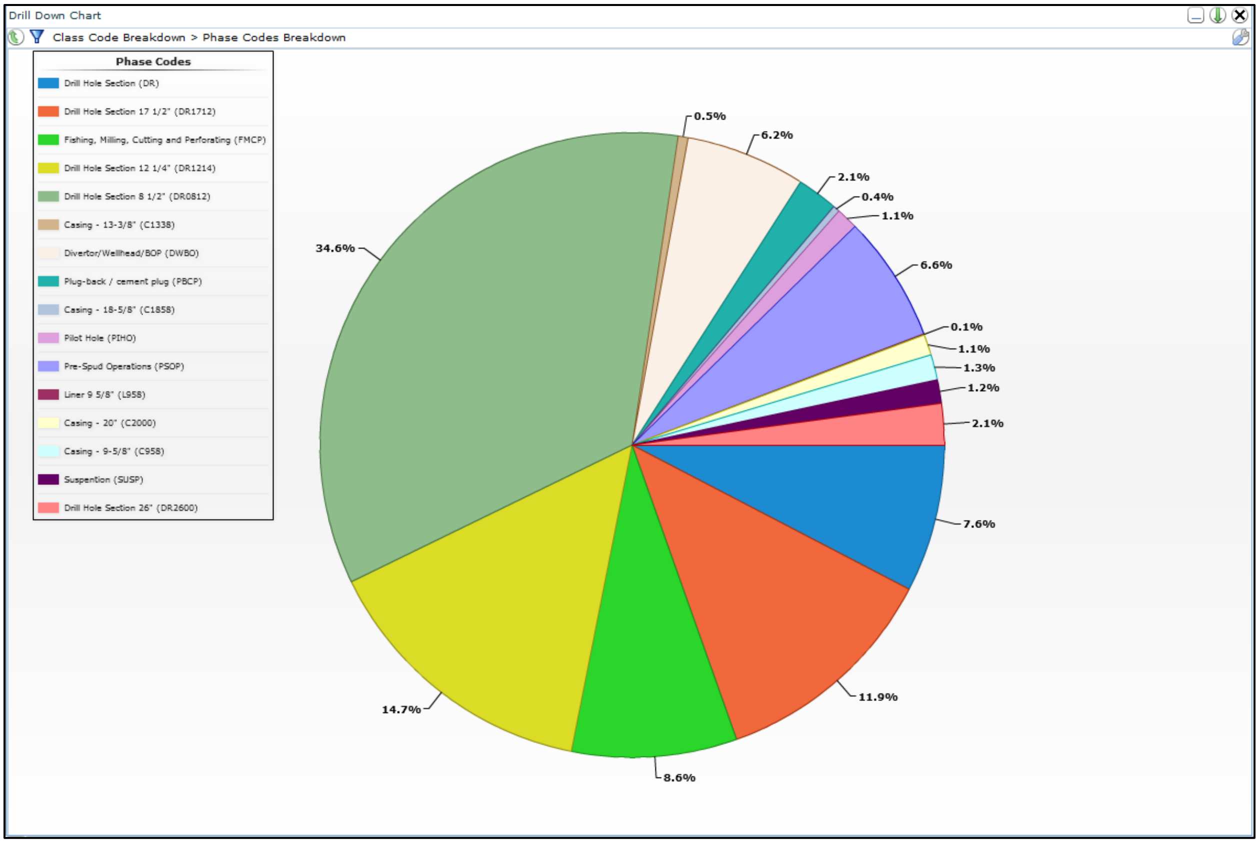

Figure 106: Geo Well #21; Percentage of Programmed Phase Code Breakdowns

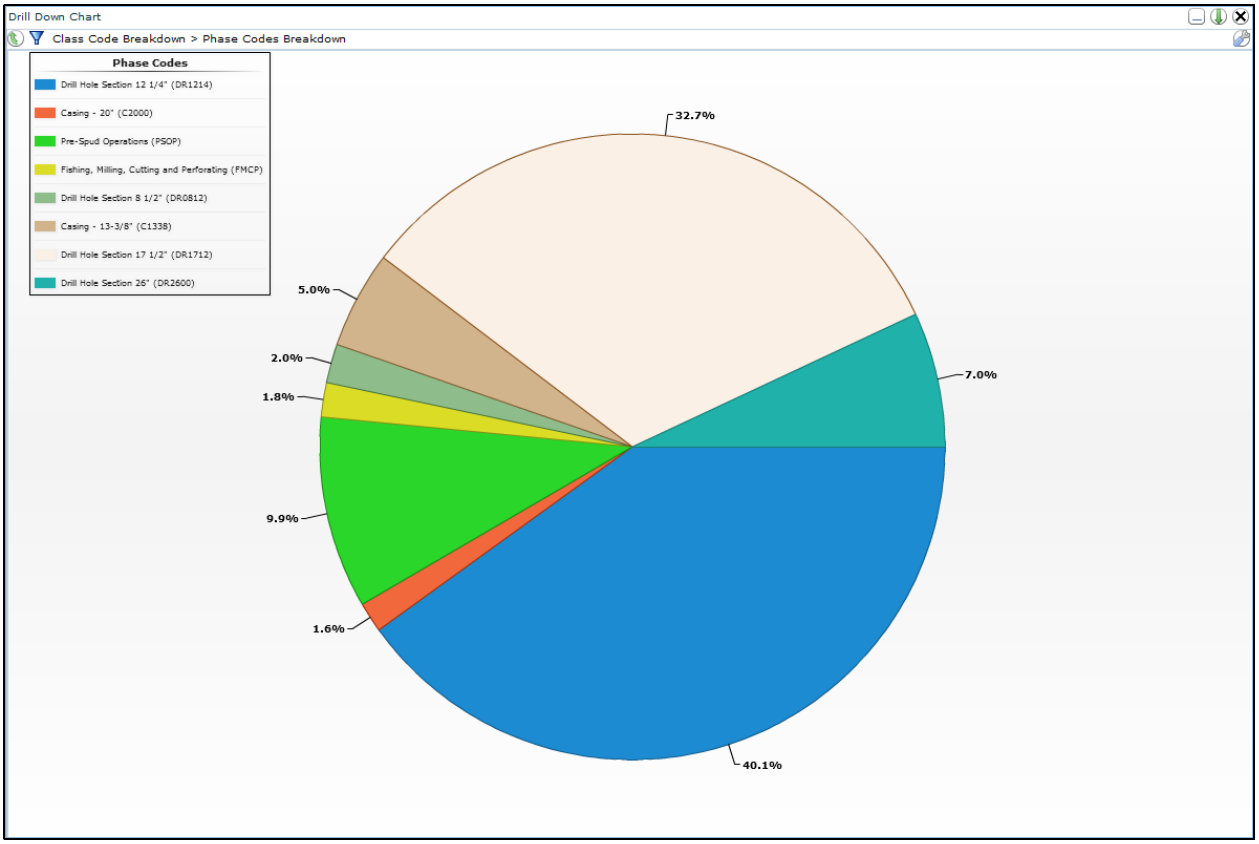

Figure 107: Geo Well #21; Percentage of Trouble during Programmed Phase Code Breakdowns

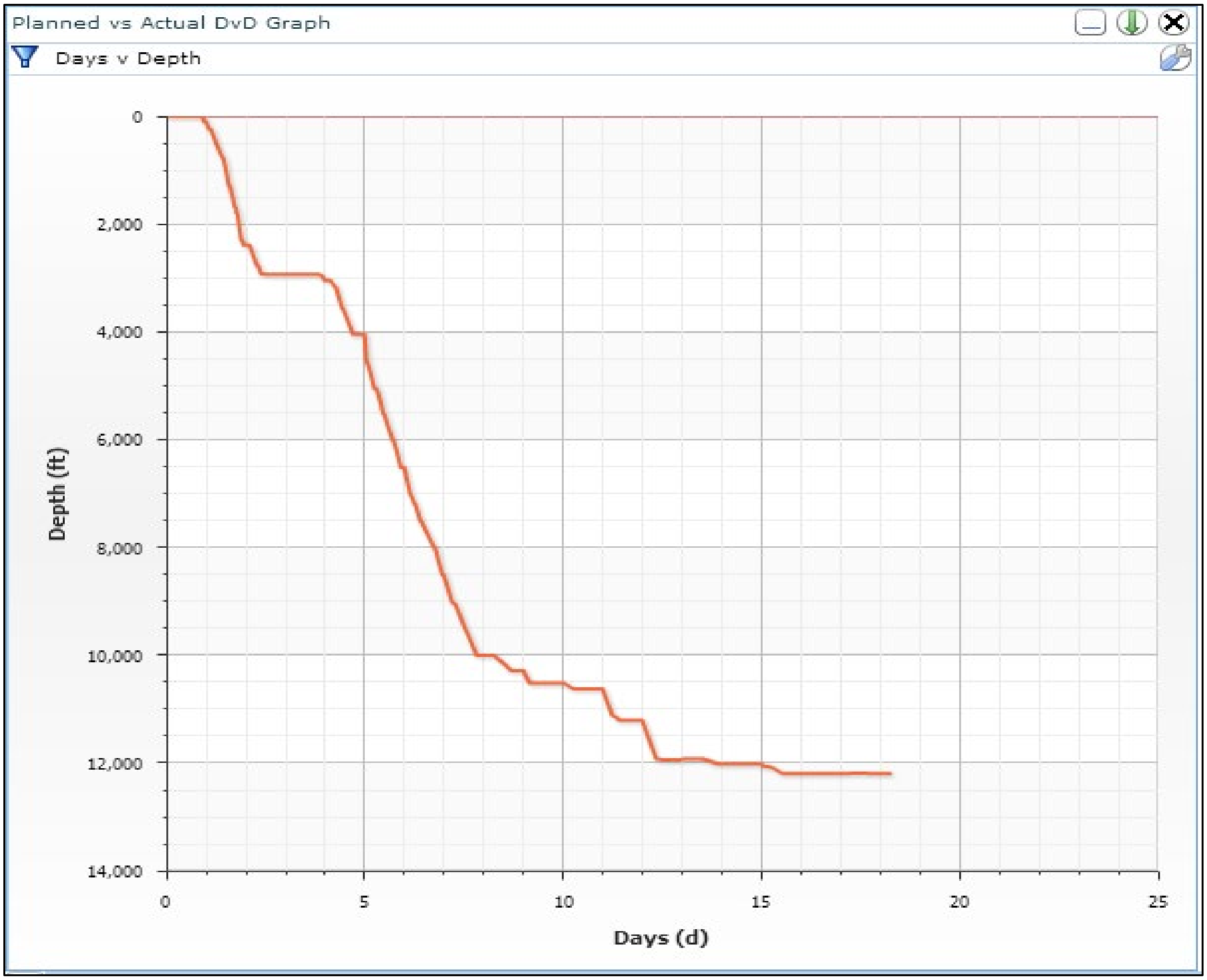

Figure 108: Oil Well #1; Days vs. Depth Drilled

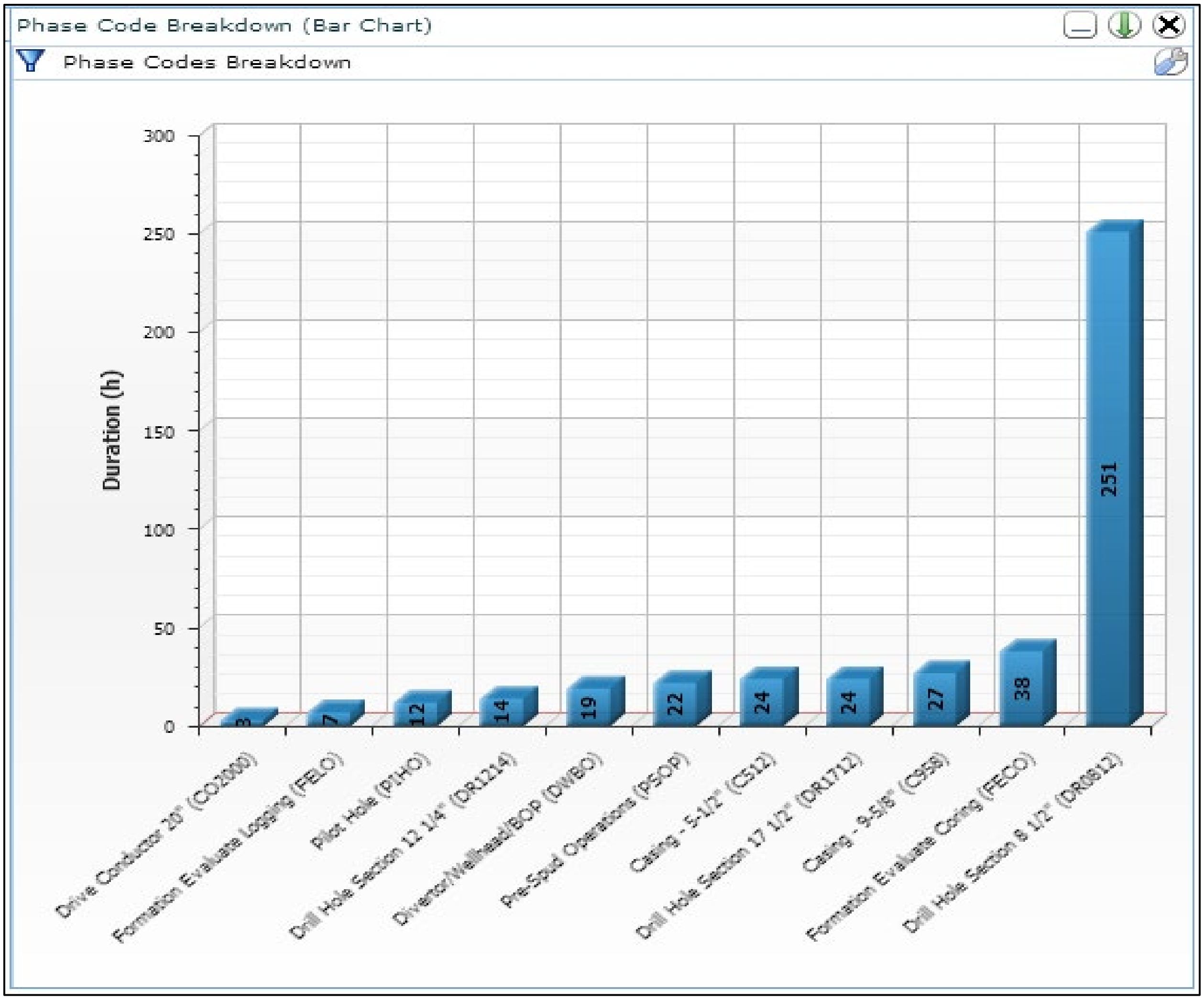

Figure 109: Oil Well #1; Phase Code Breakdown

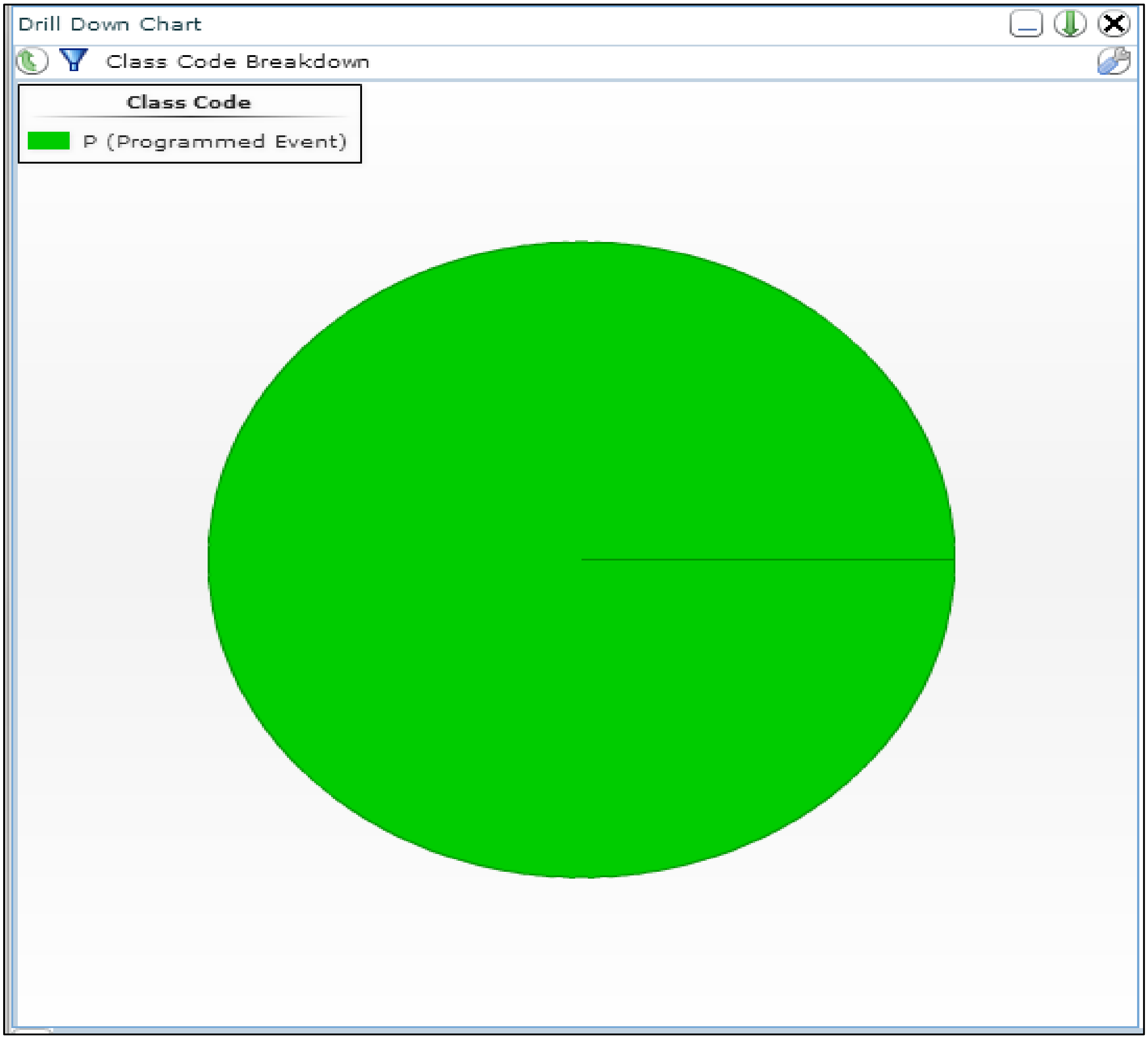

Figure 110: Oil Well #1; Percentage of Class Code Breakdown

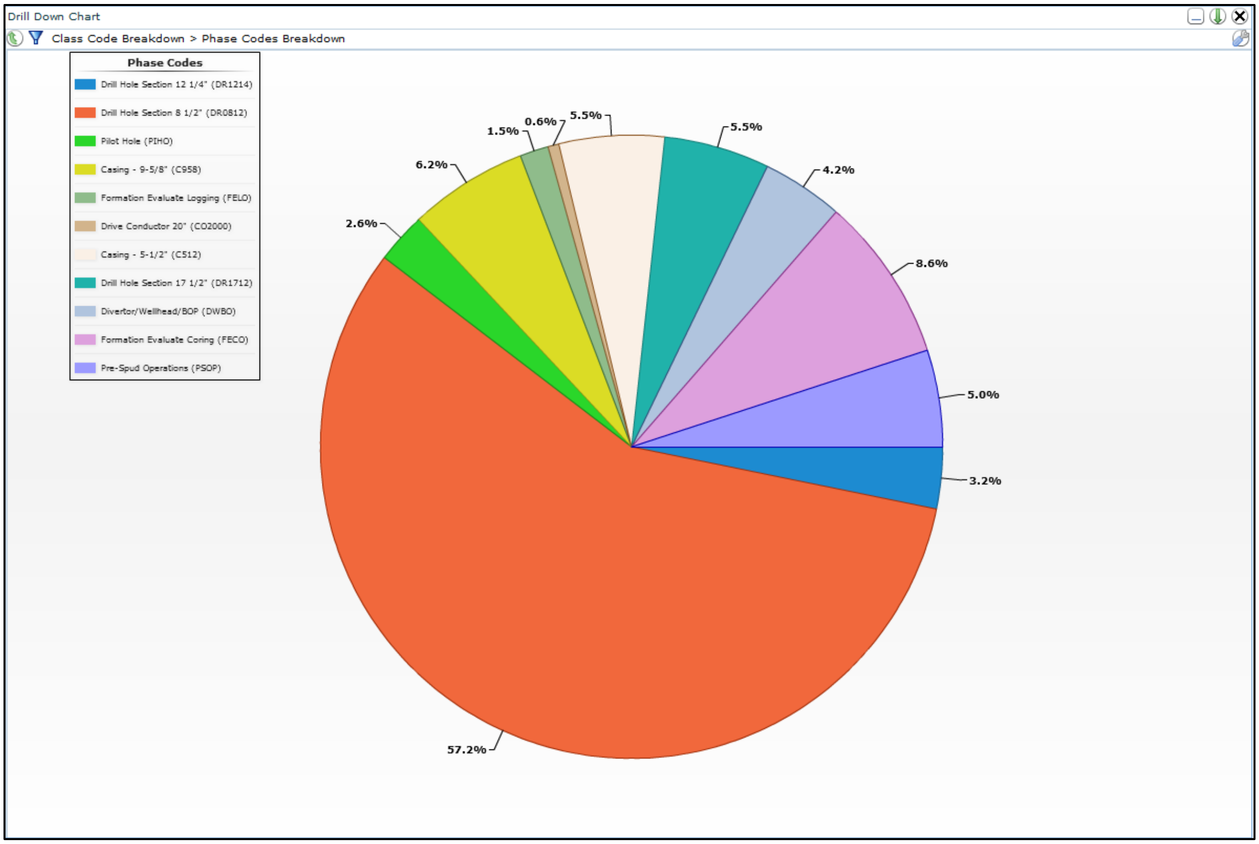

Figure 111: Oil Well #1; Percentage of Programmed Phase Code Breakdown

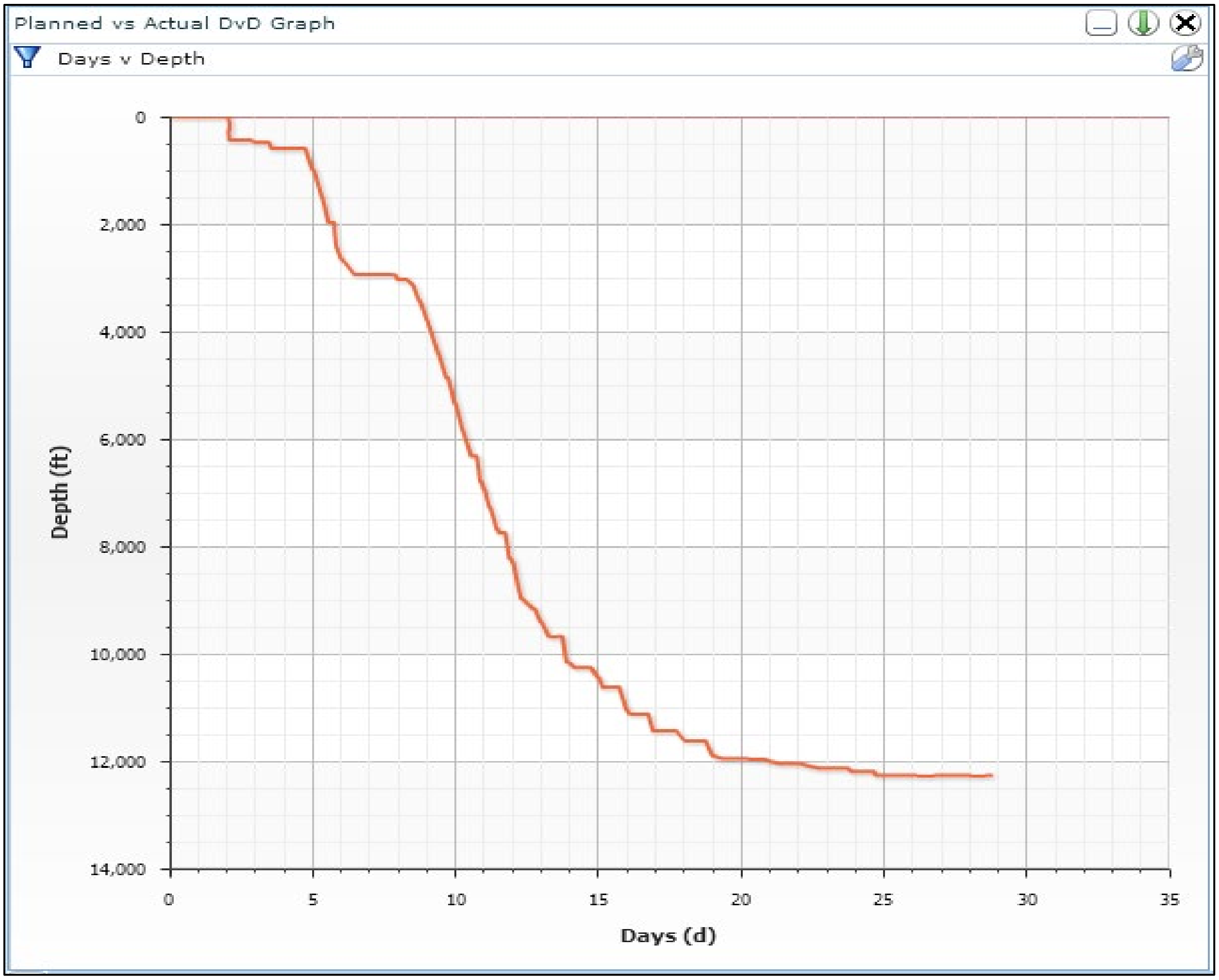

Figure 112: Oil Well #2; Days vs. Depth Drilled

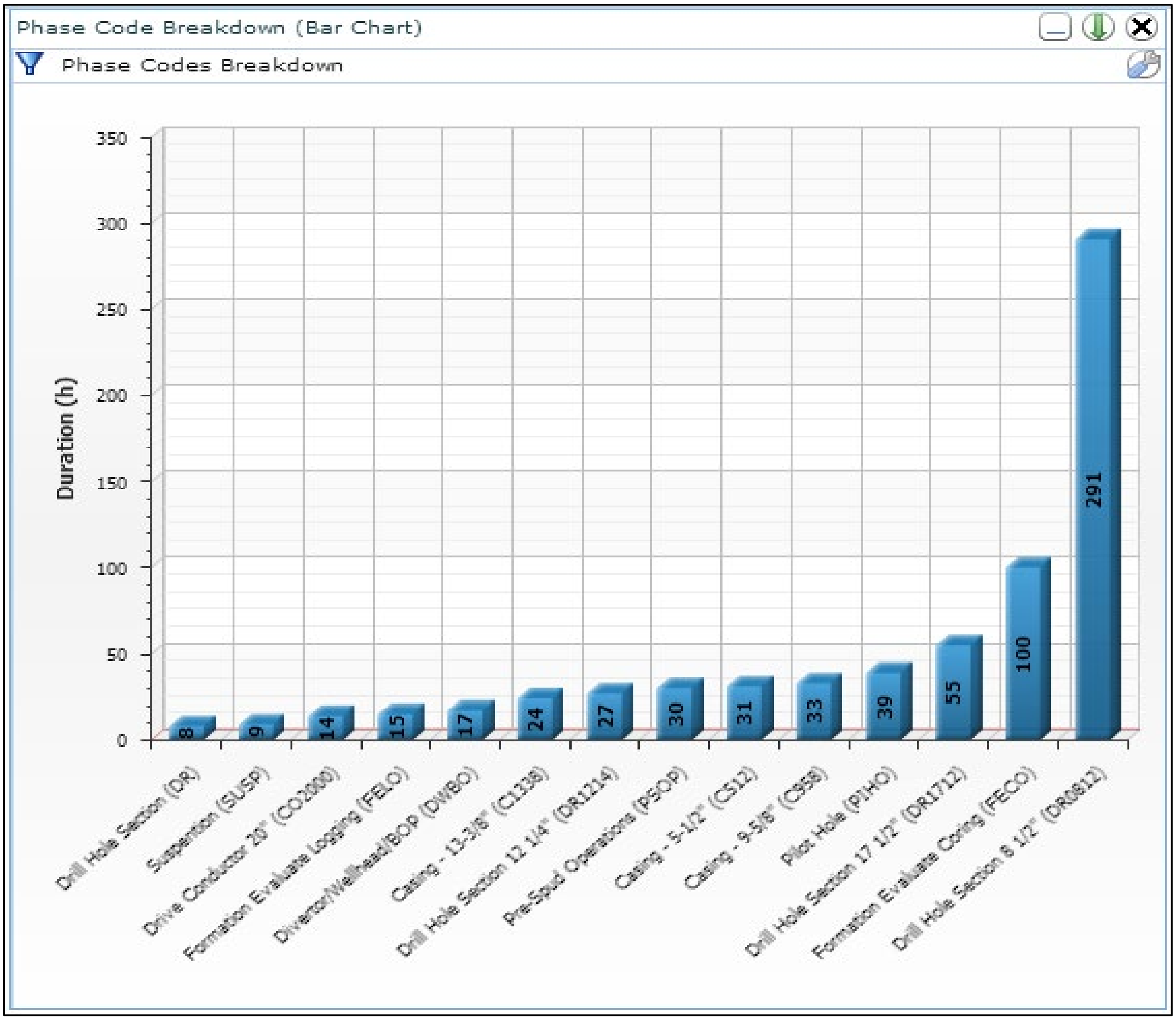

Figure 113: Oil Well #2; Phase Code Breakdown

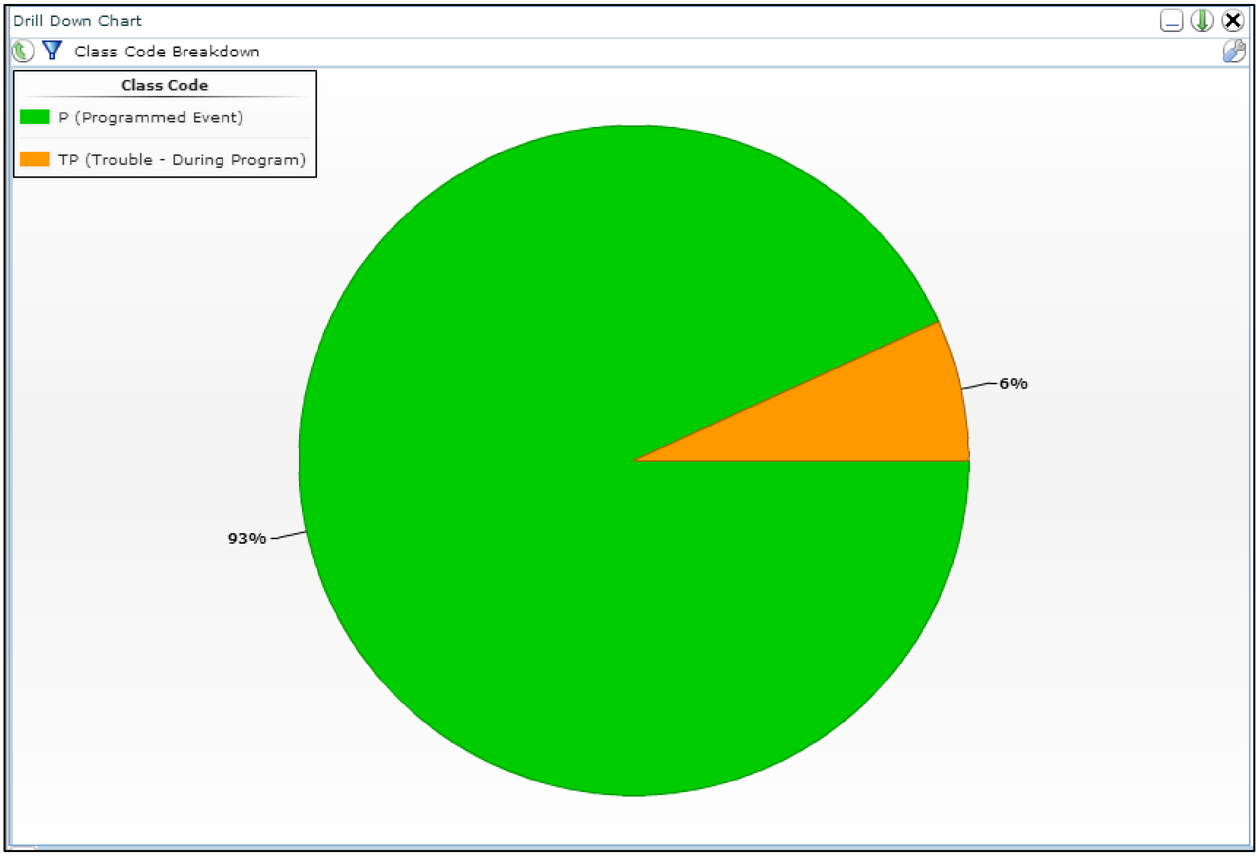

Figure 114: Oil Well #2; Percentage of Class Code Breakdown

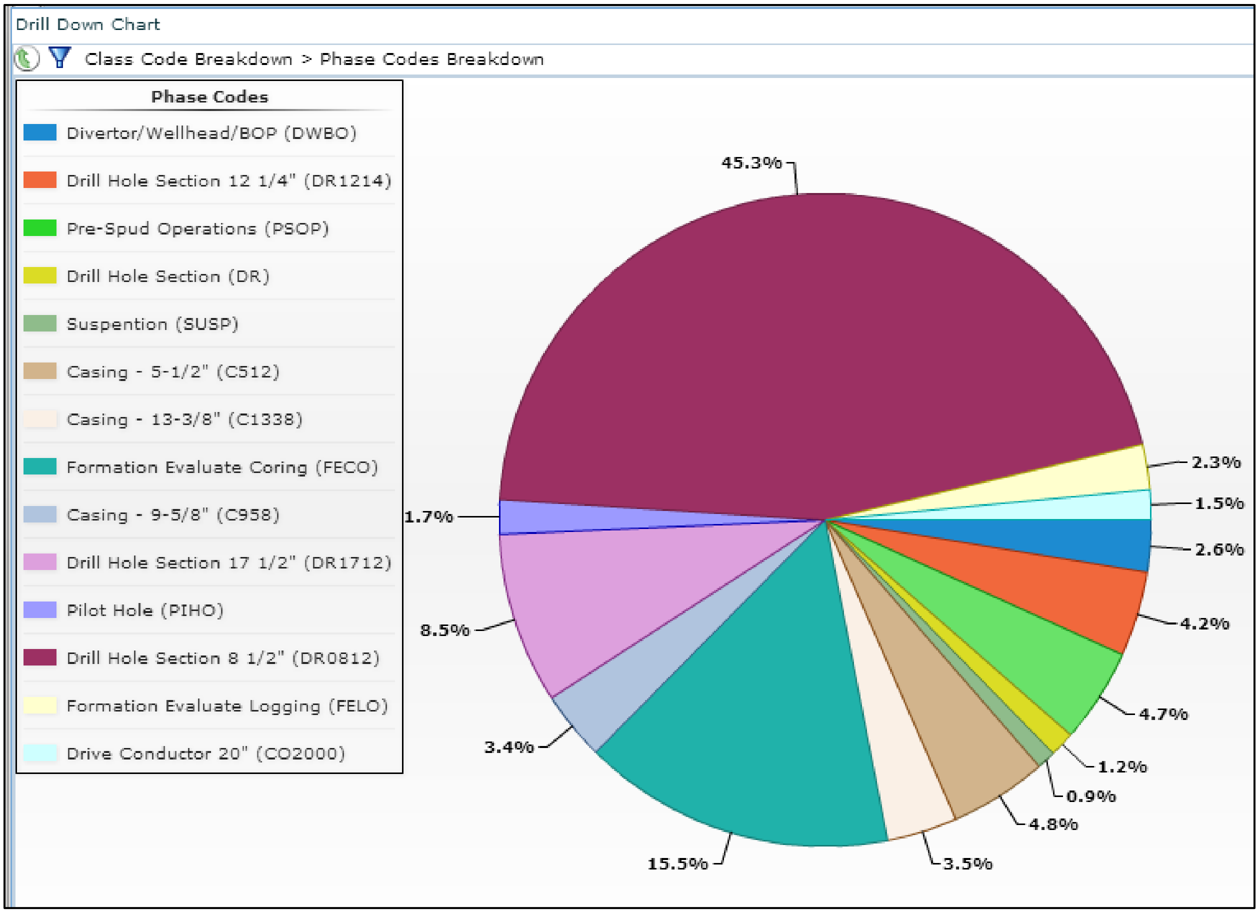

Figure 115: Oil Well #2; Percentage of Programmed Phase Code Breakdowns

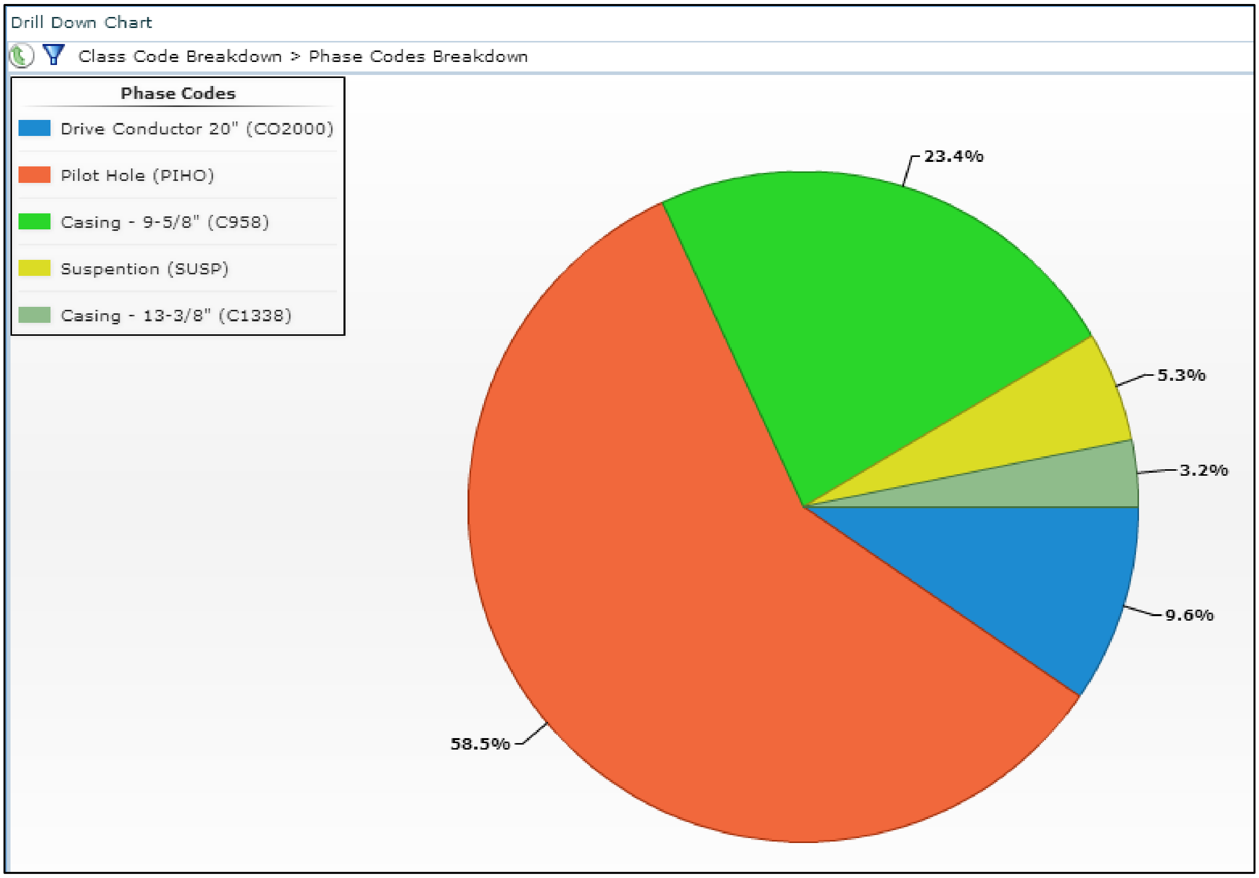

Figure 116: Oil Well #2; Percentage of Trouble during Programmed Phase Code Breakdowns

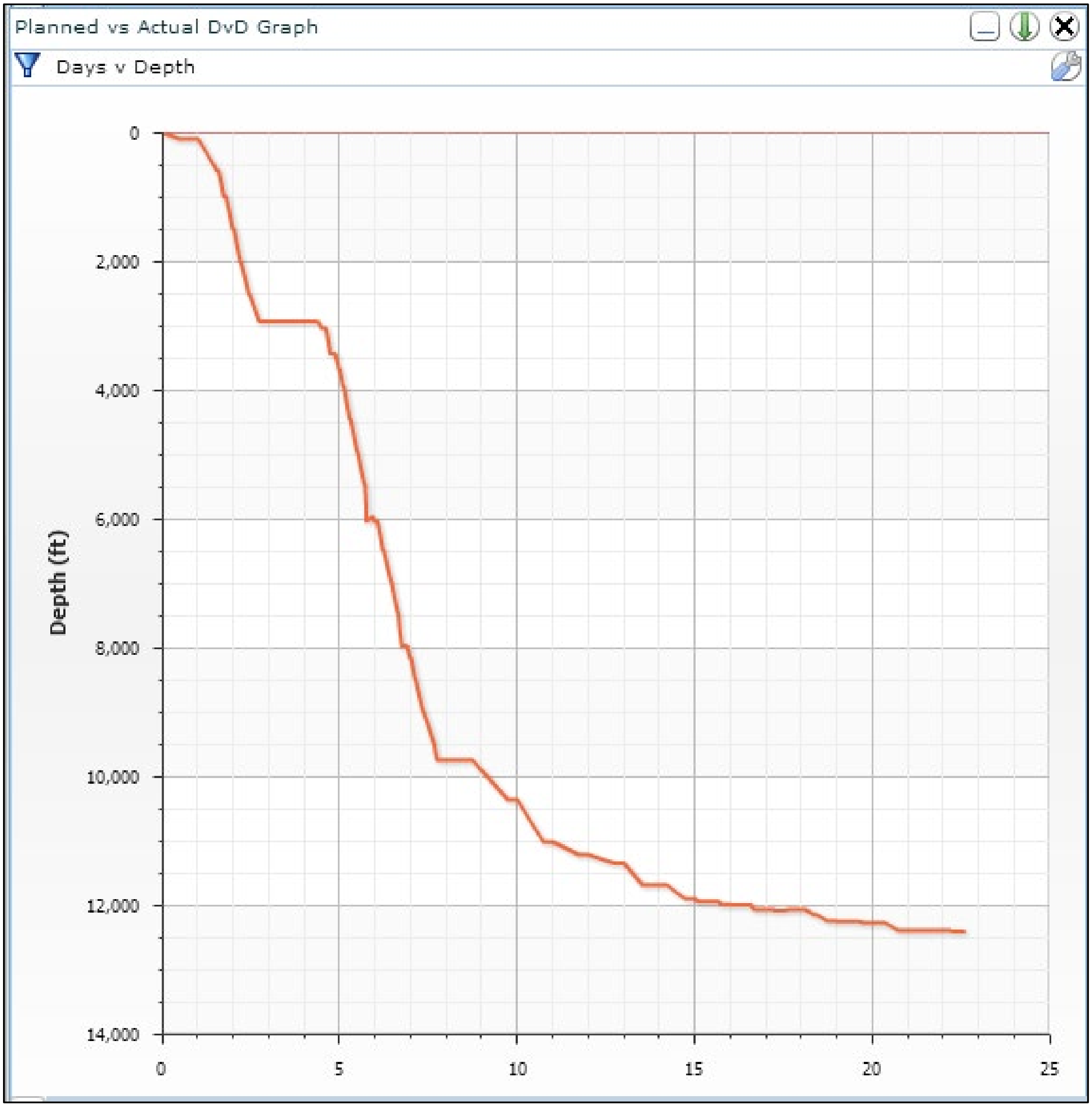

Figure 117: Oil Well #3; Days vs. Depth Drilled

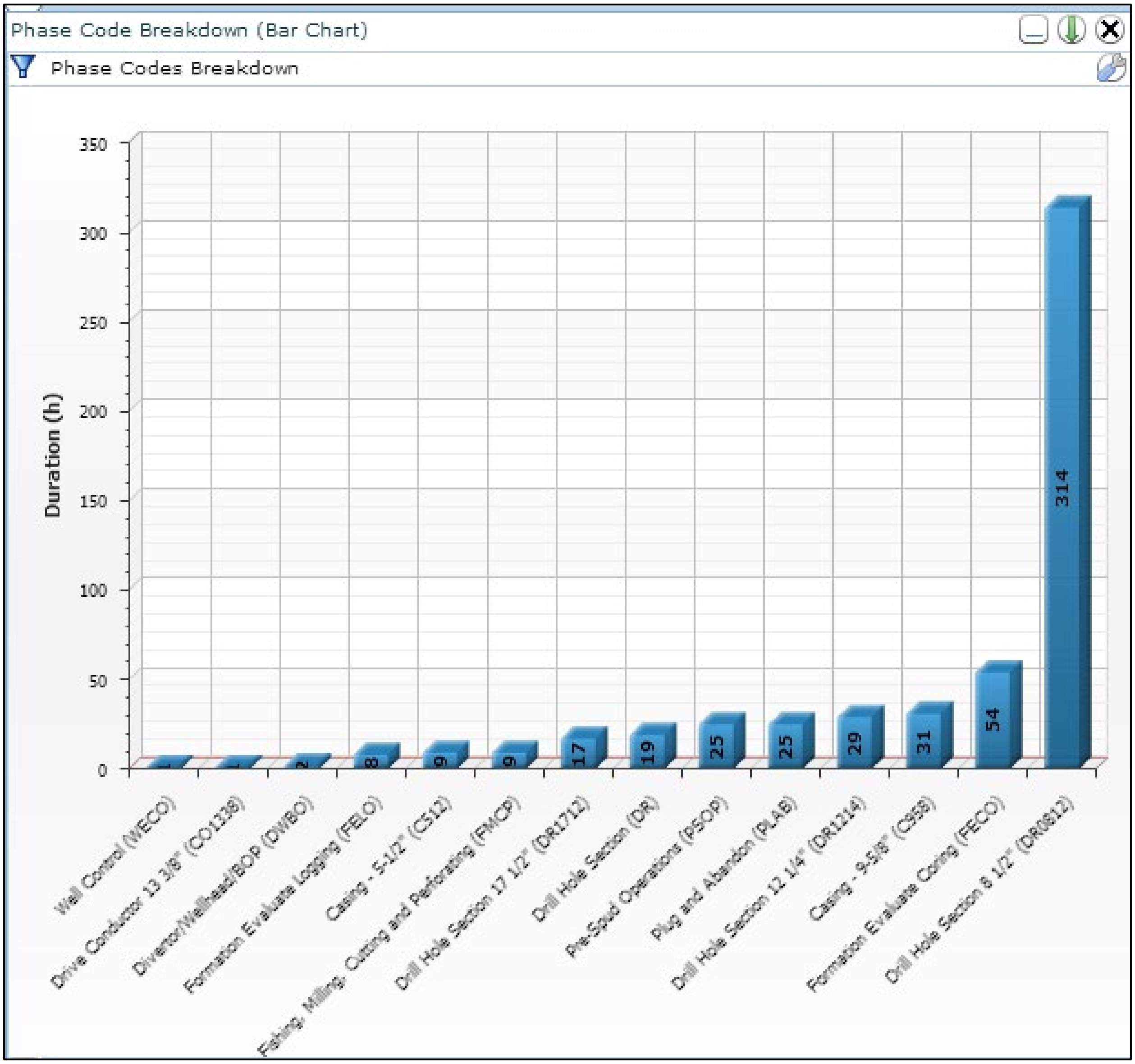

Figure 118: Oil Well #3; Phase Code Breakdown

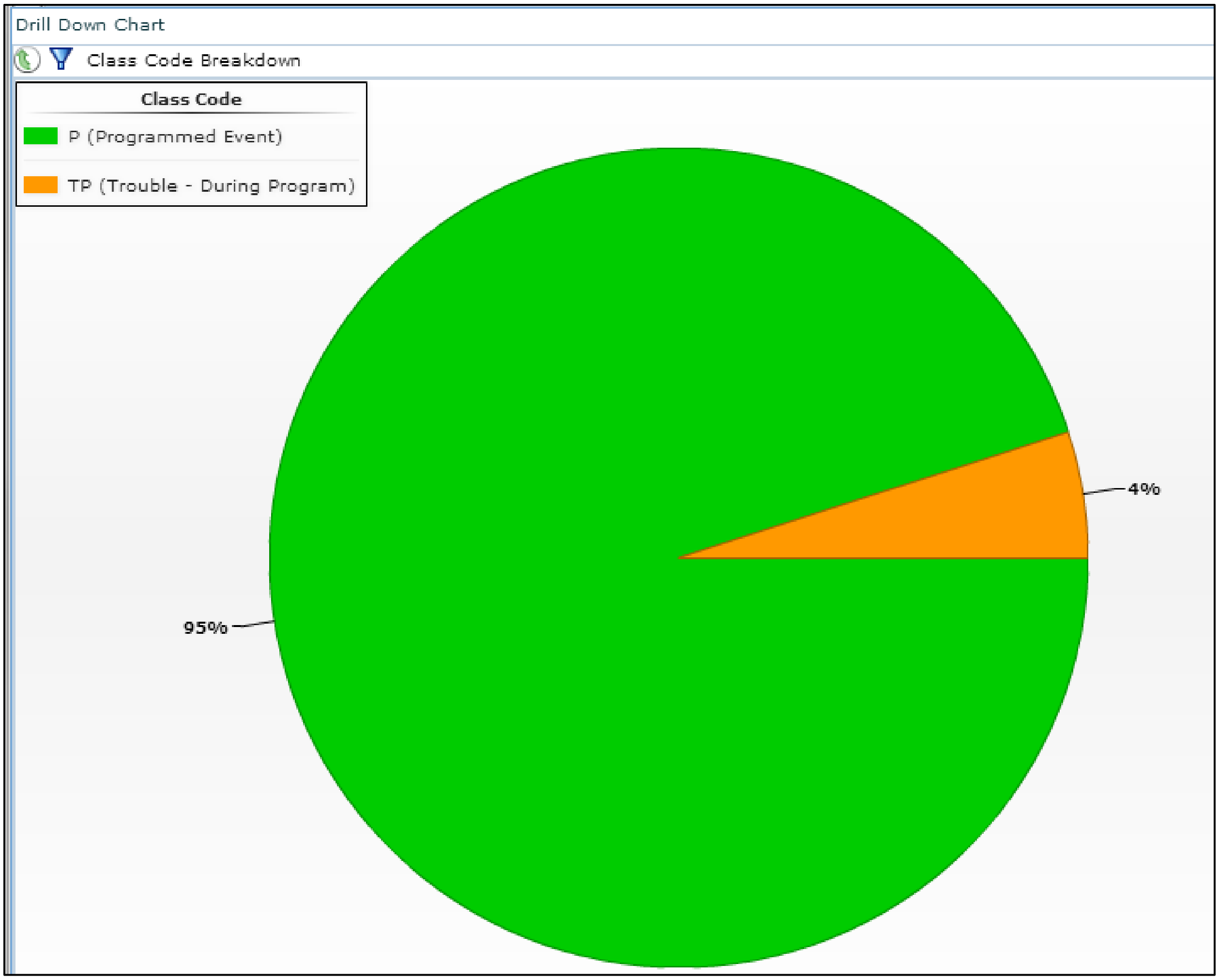

Figure 119: Oil Well #3; Percentage of Class Code Breakdowns

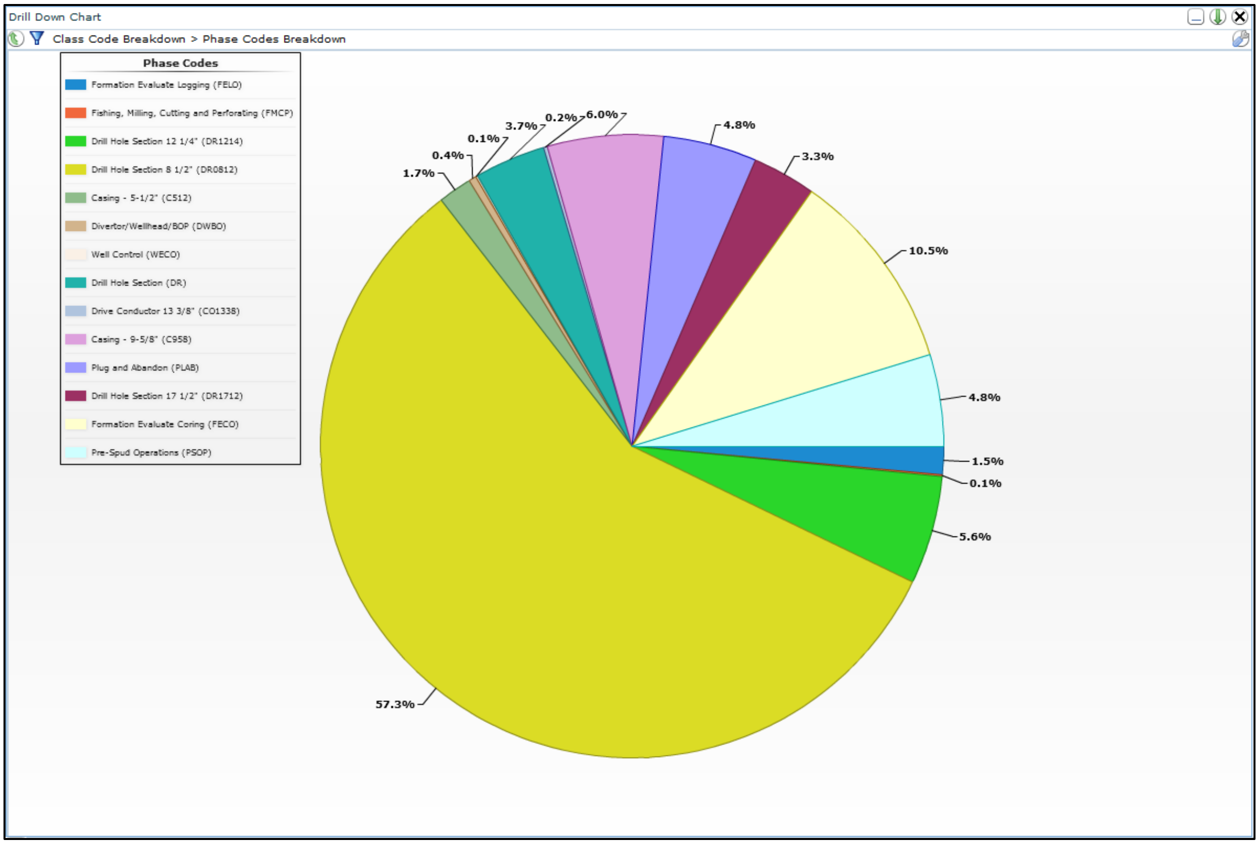

Figure 120: Oil Well #3; Percentage of Programmed Phase Code Breakdowns

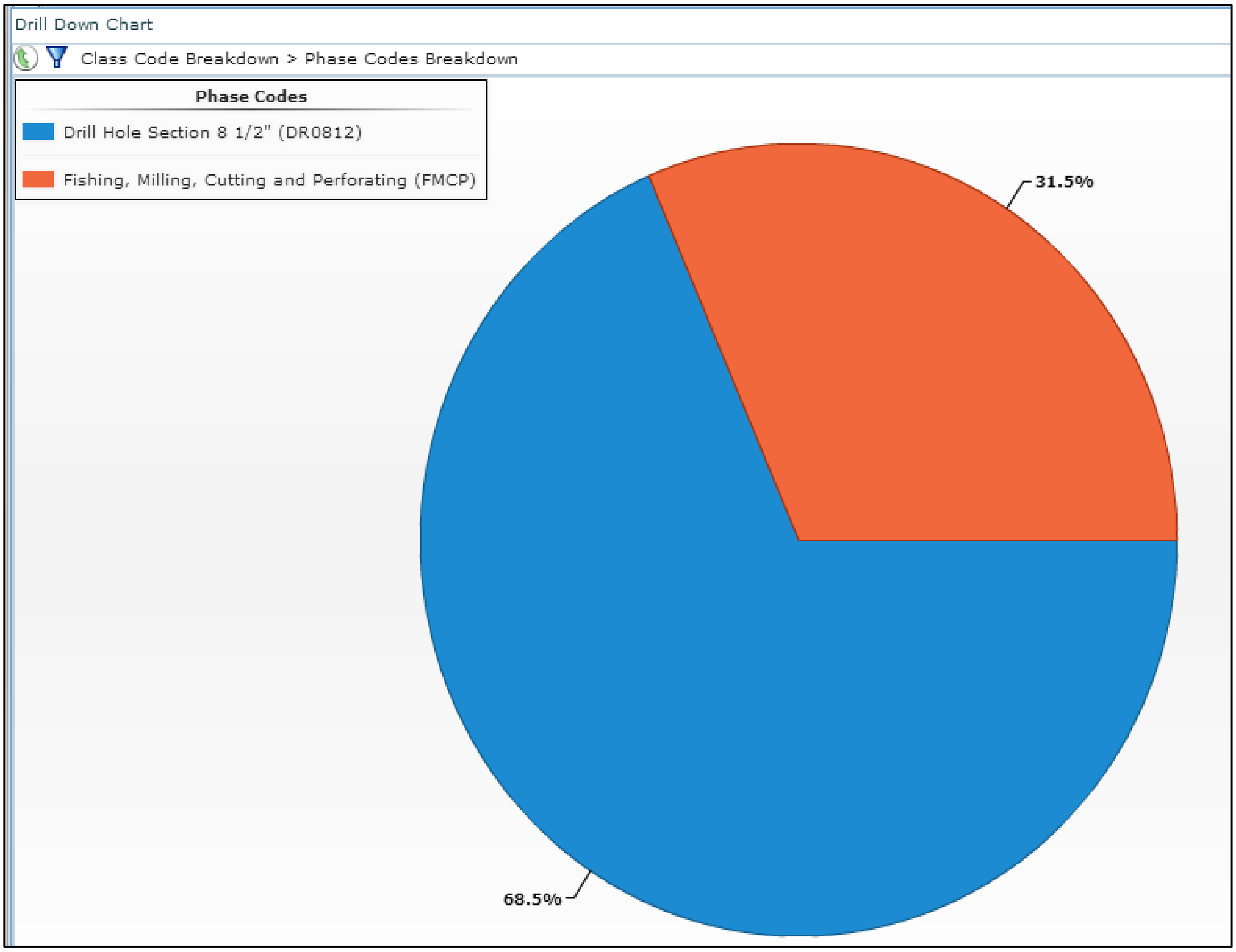

Figure 121: Oil Well #3; Percentage of Trouble during Programmed Phase Code Breakdowns

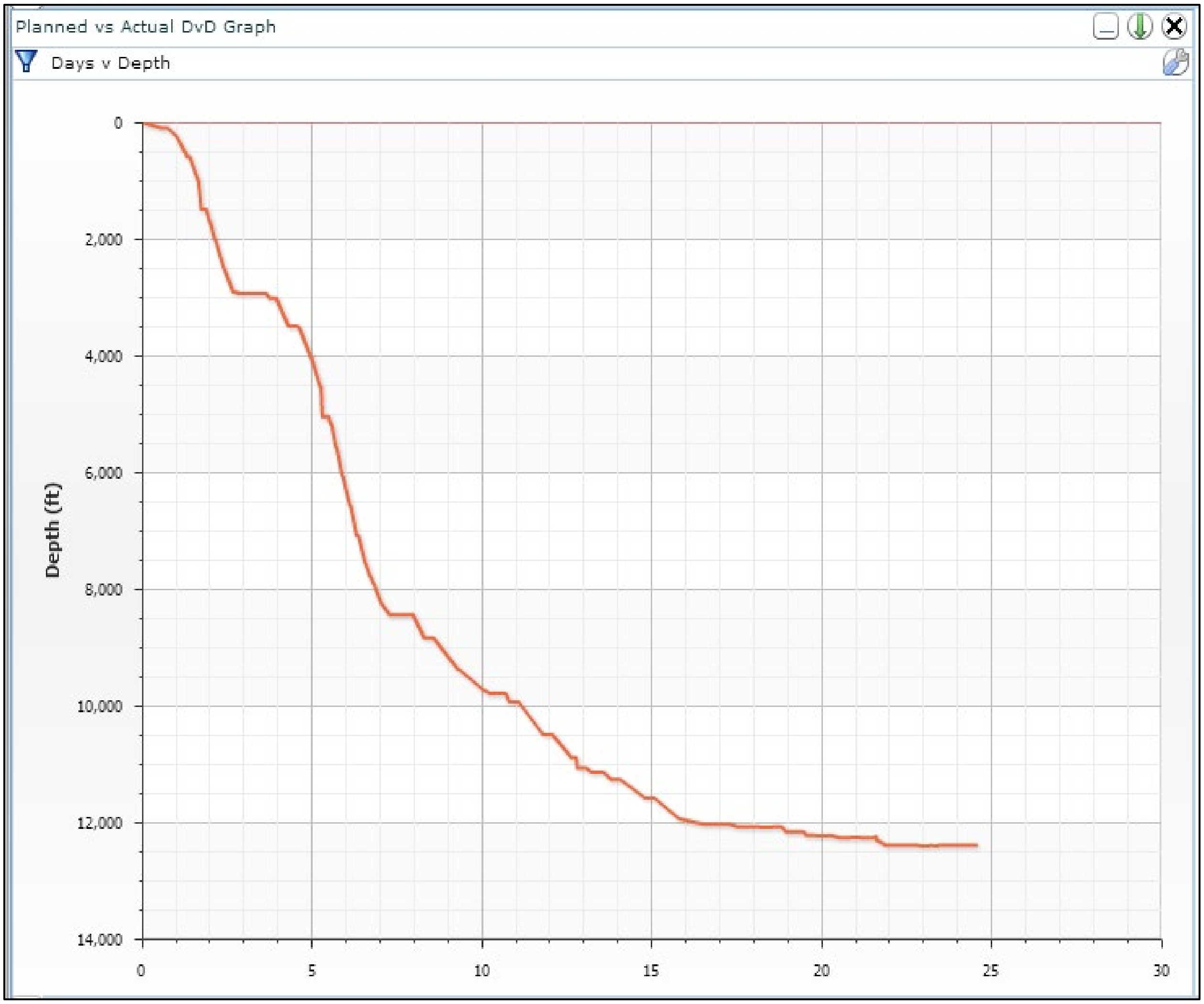

Figure 122: Oil Well #4; Days vs. Depth Drilled

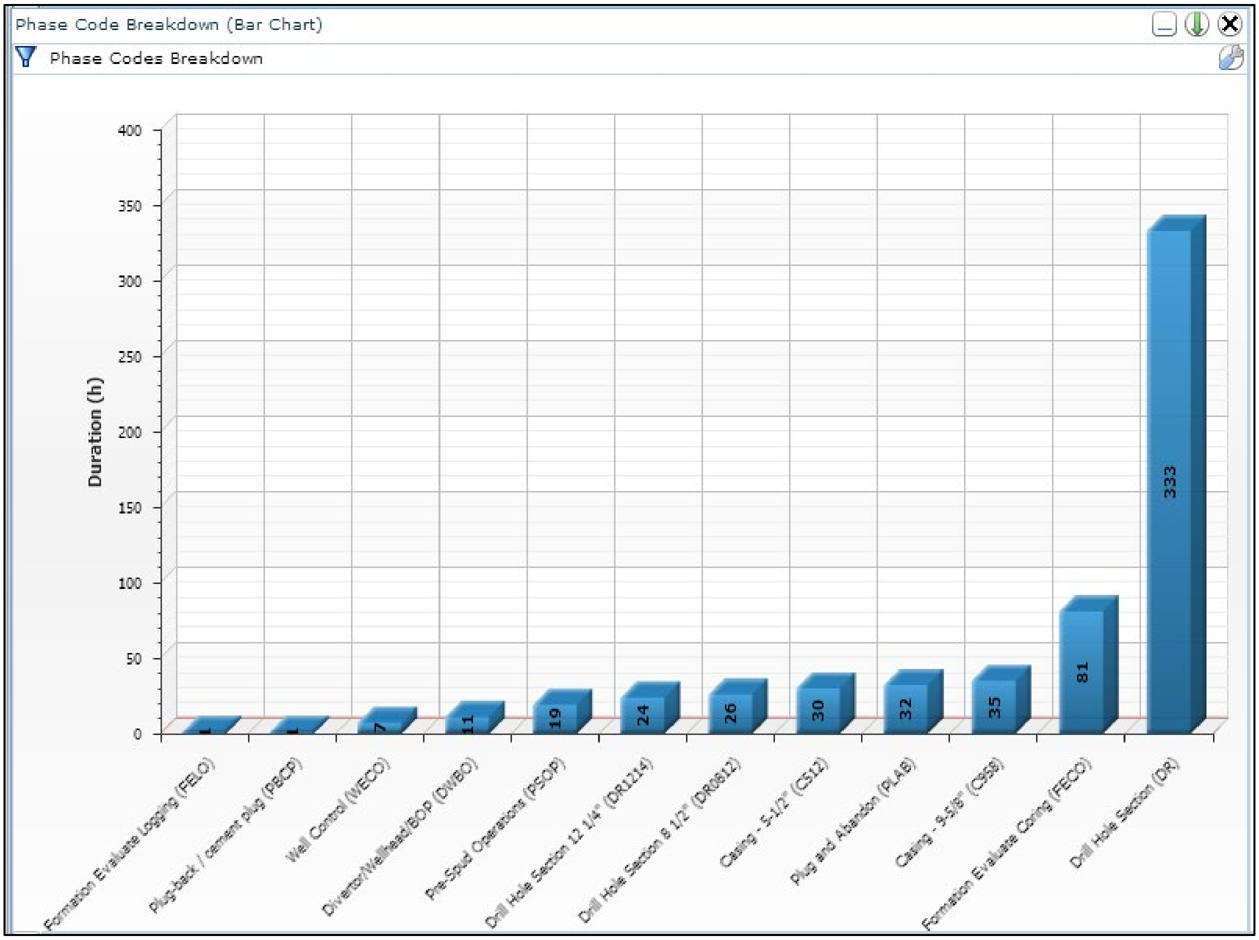

Figure 123: Oil Well #4; Phase Code Breakdown

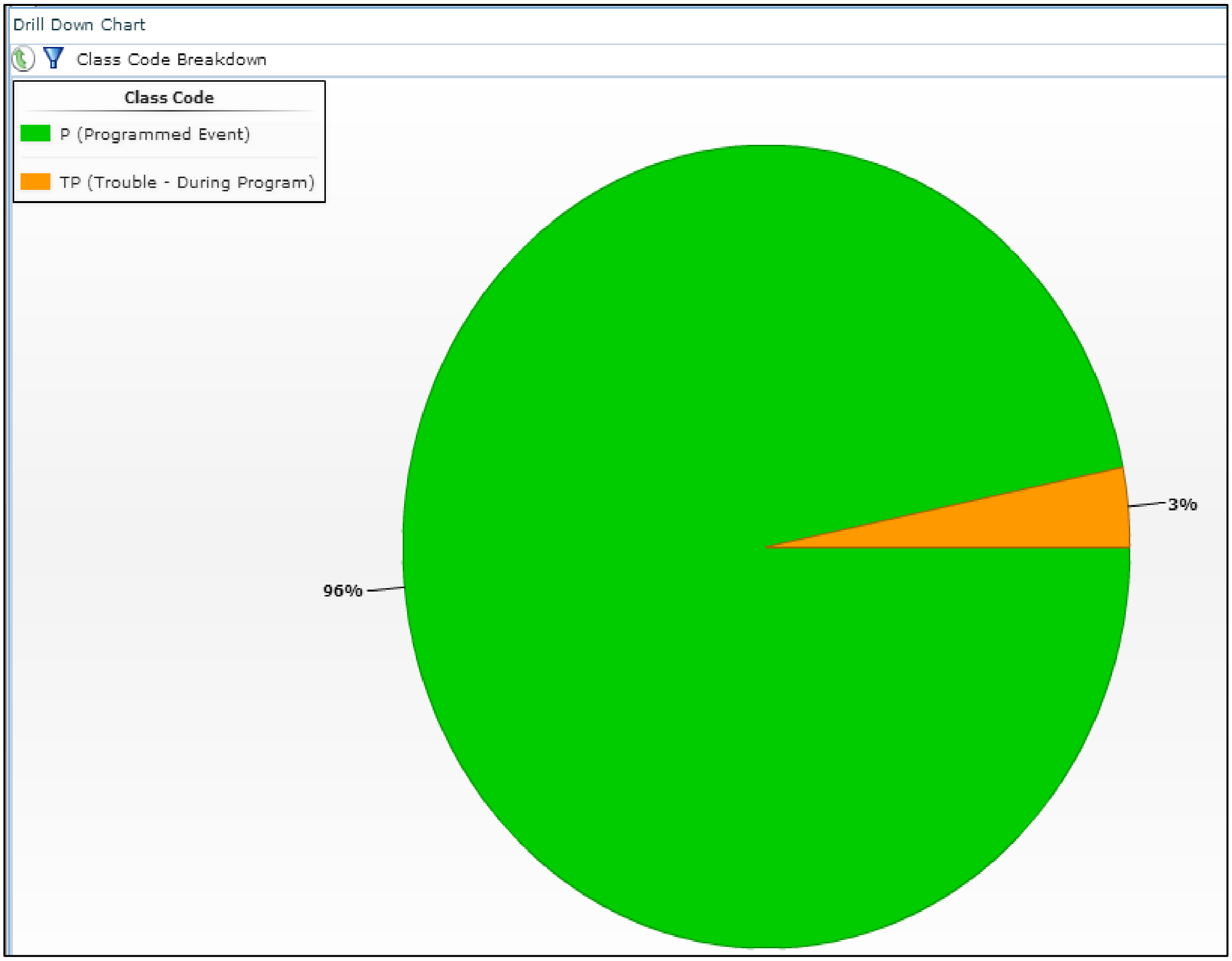

Figure 124: Oil Well #4; Percentage of Class Code Breakdowns

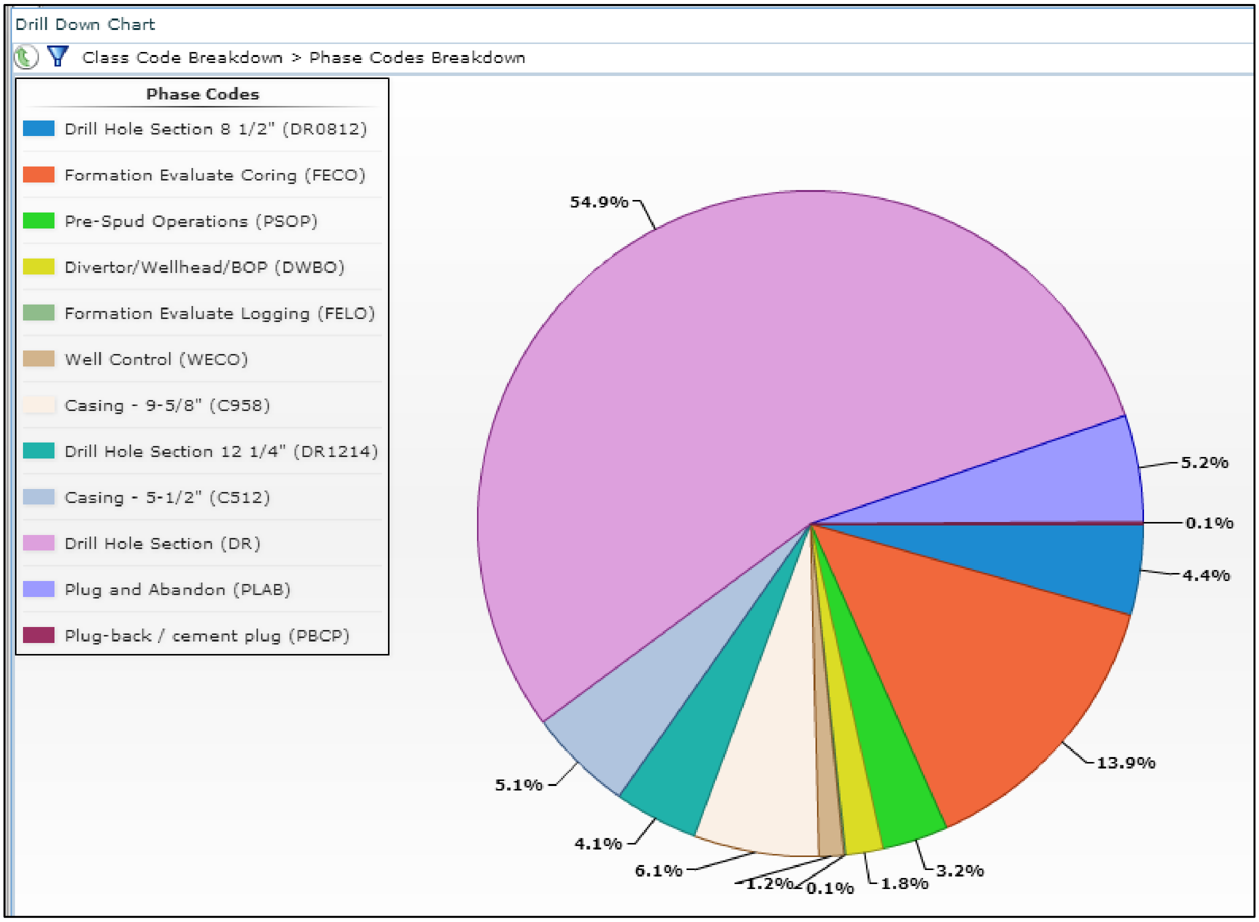

Figure 125: Oil Well #4; Percentage of Programmed Phase Code Breakdowns

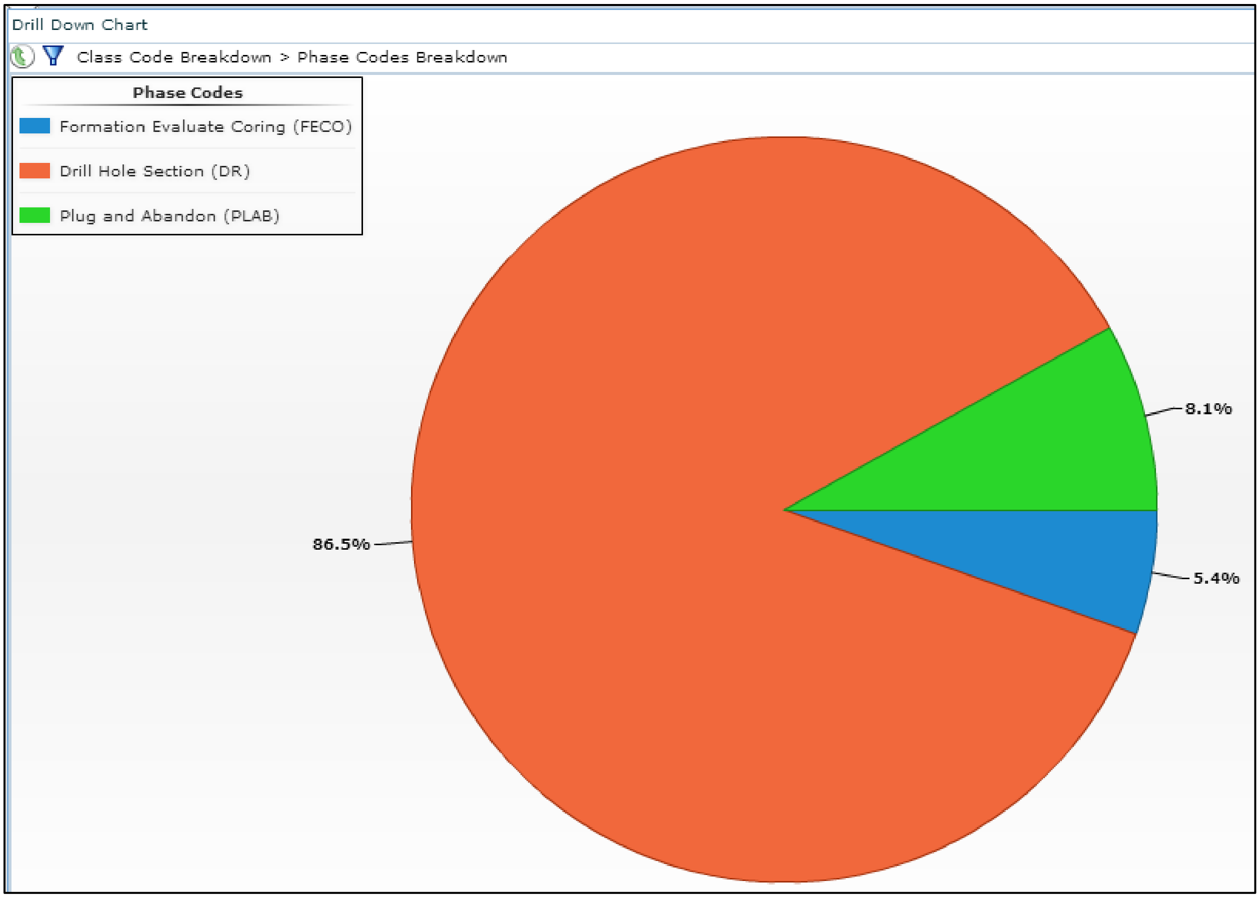

Figure 126: Oil Well #4; Percentage of Trouble during Programmed Phase Code Breakdowns

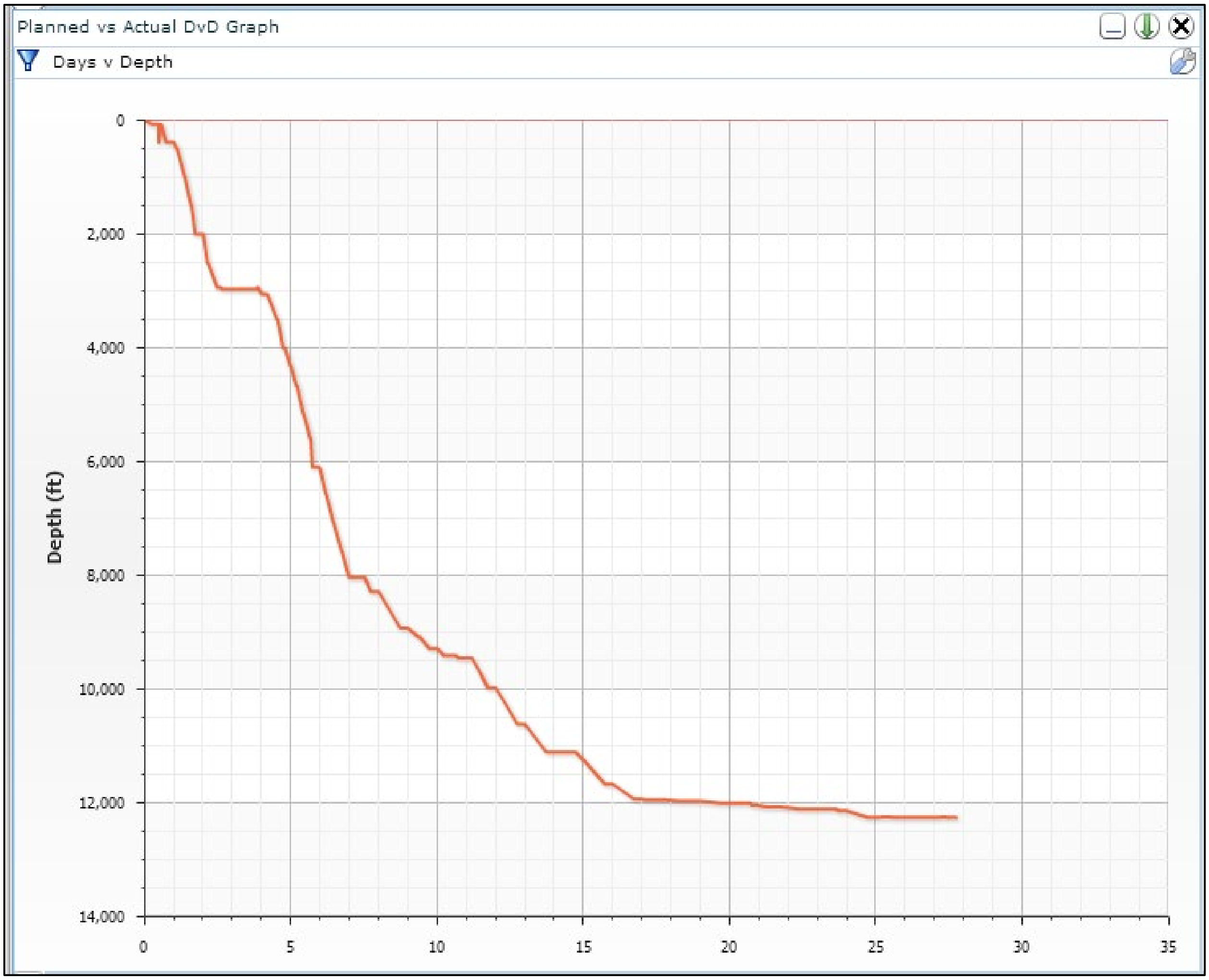

Figure 127: Oil Well #5; Days vs. Depth Drilled

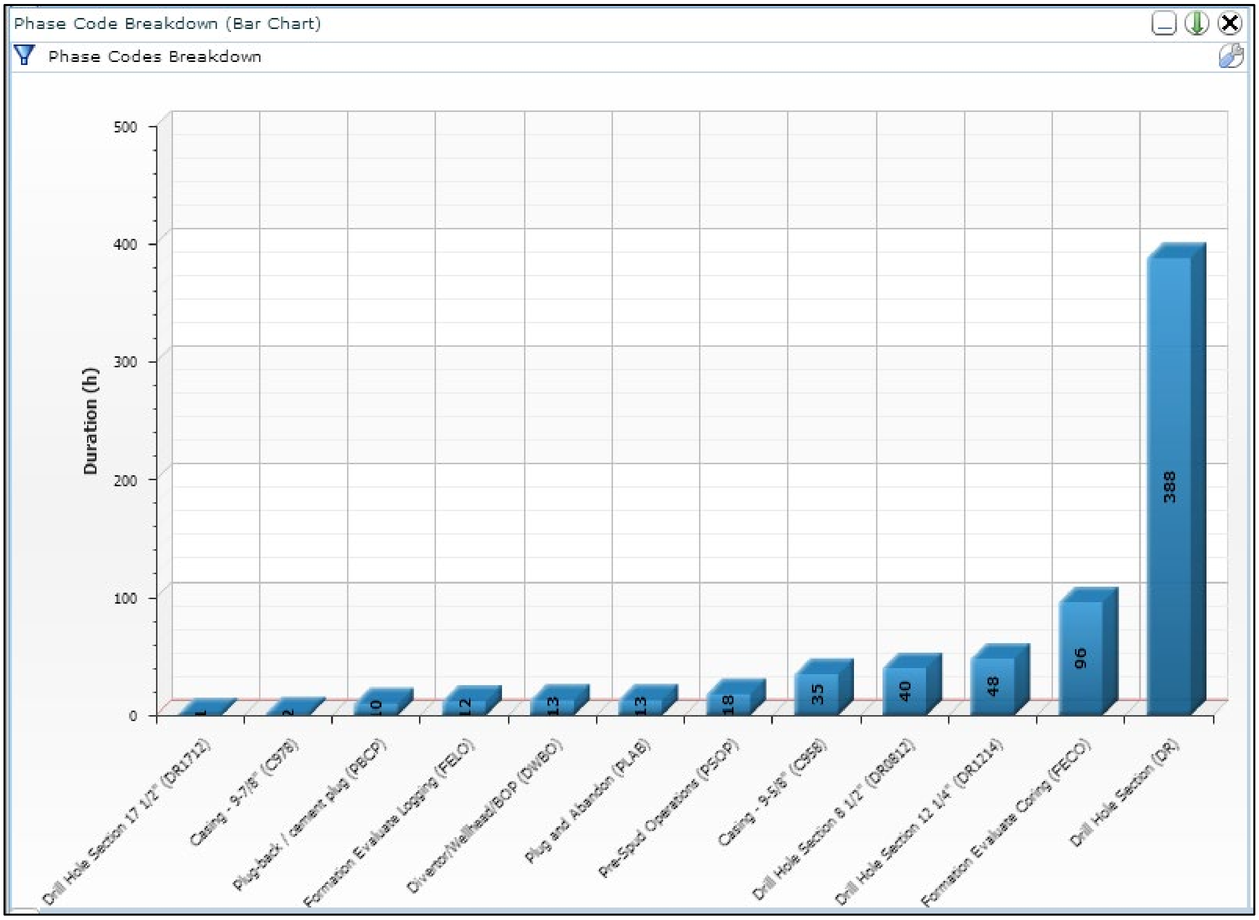

Figure 128: Oil Well #5; Phase Code Breakdown

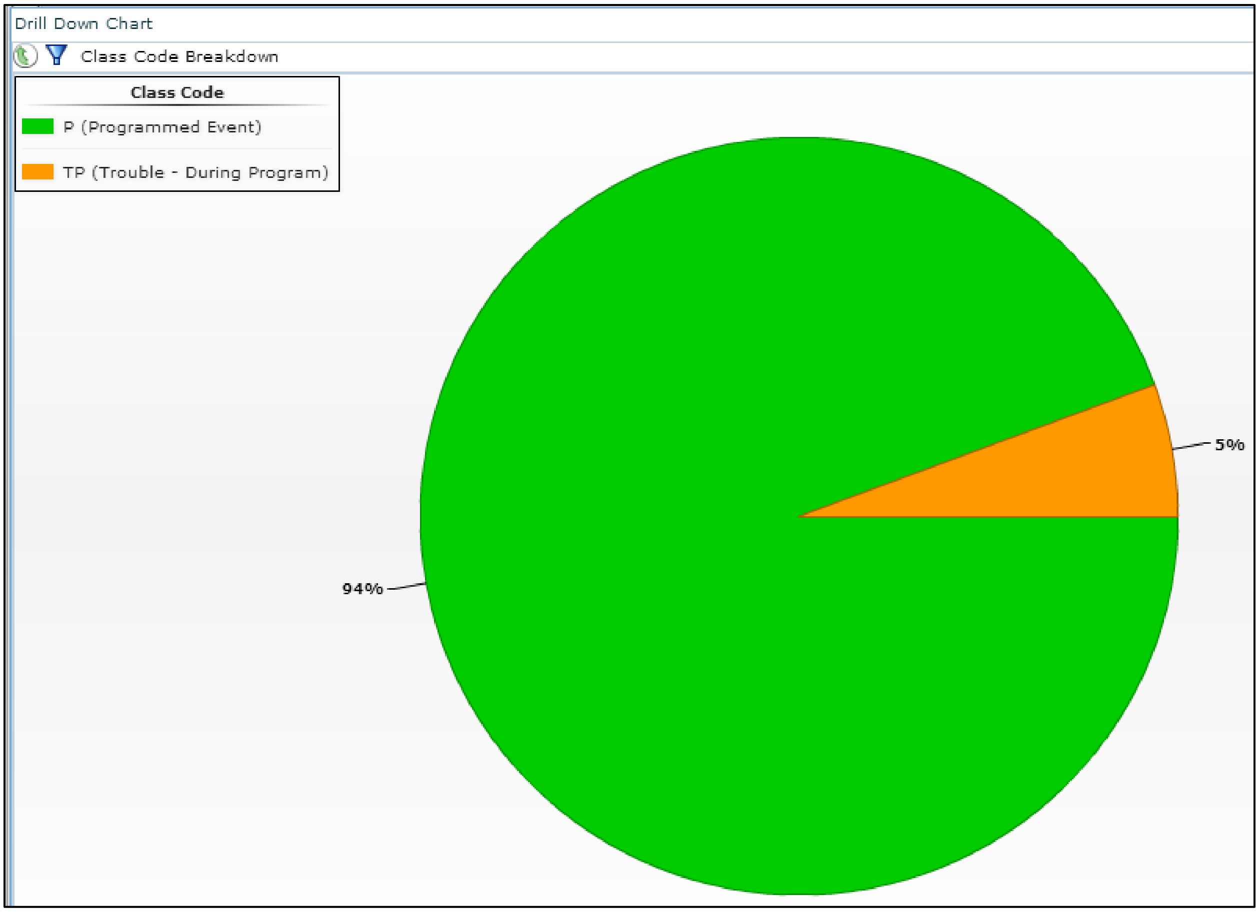

Figure 129: Oil Well #5; Percentage of Class Code Breakdowns

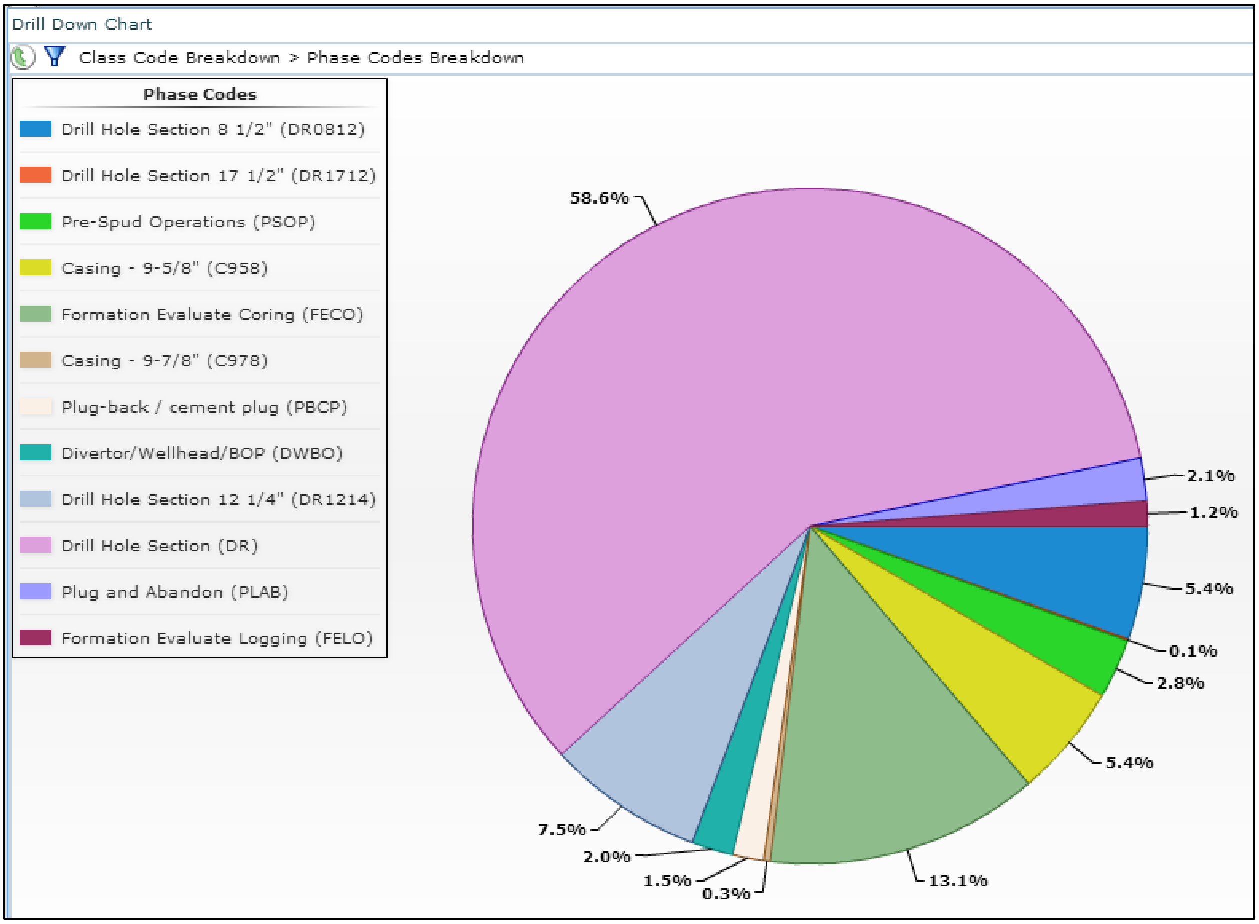

Figure 130: Oil Well #5; Percentage of Programmed Phase Code Breakdowns

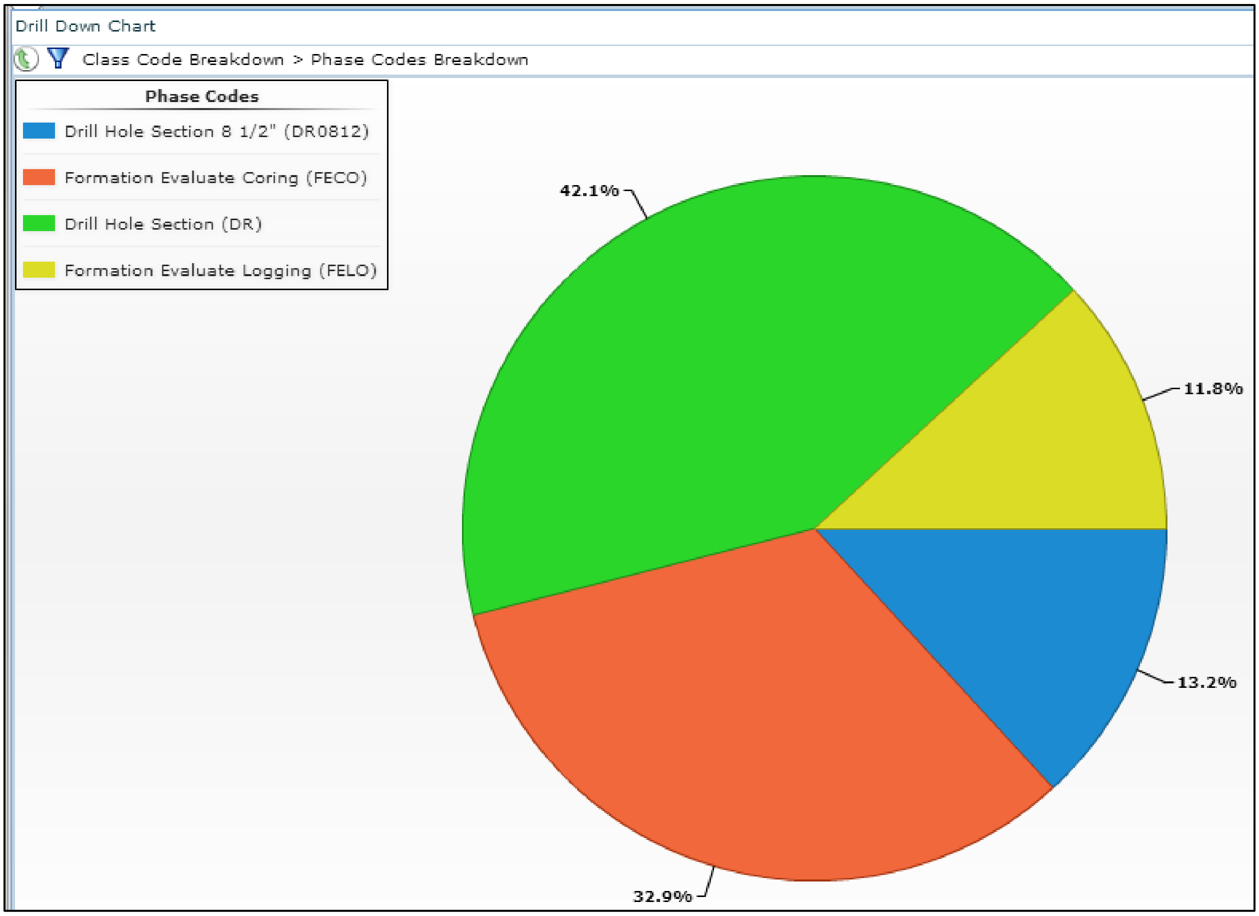

Figure 131: Oil Well #5; Percentage of Trouble during Programmed Phase Code Breakdowns

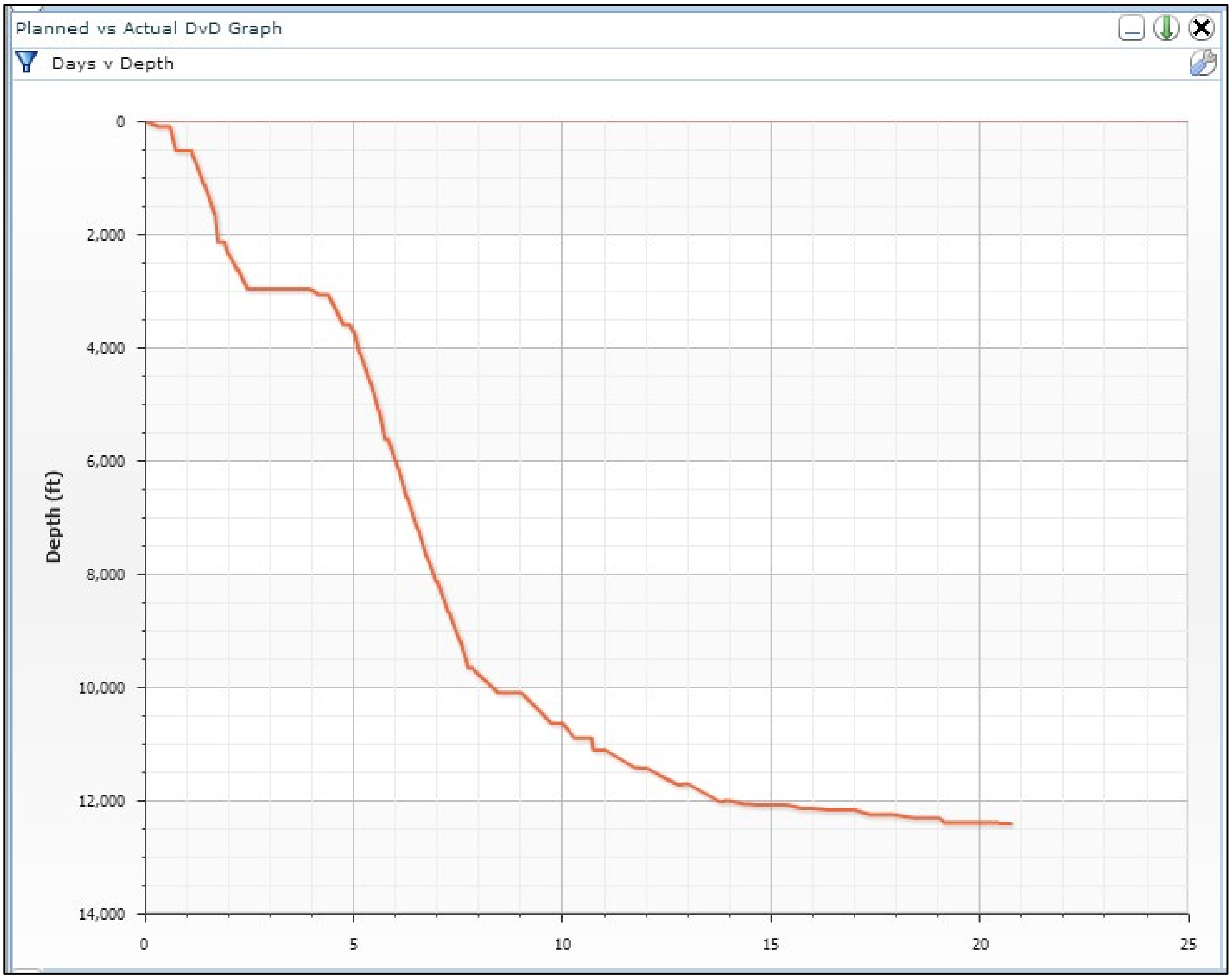

Figure 132: Oil Well #6; Days vs. Depth Drilled

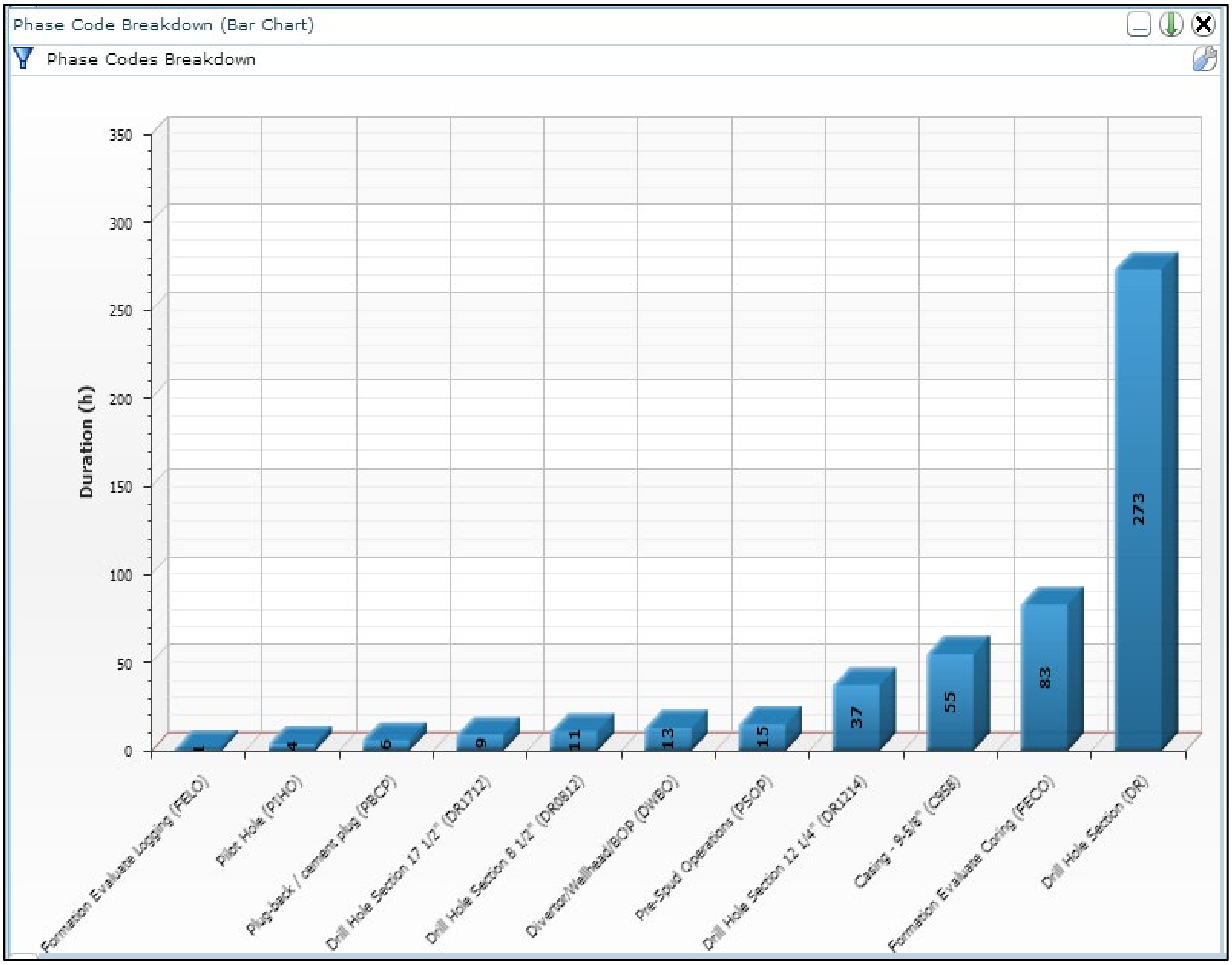

Figure 133: Oil Well #6; Phase Code Breakdown

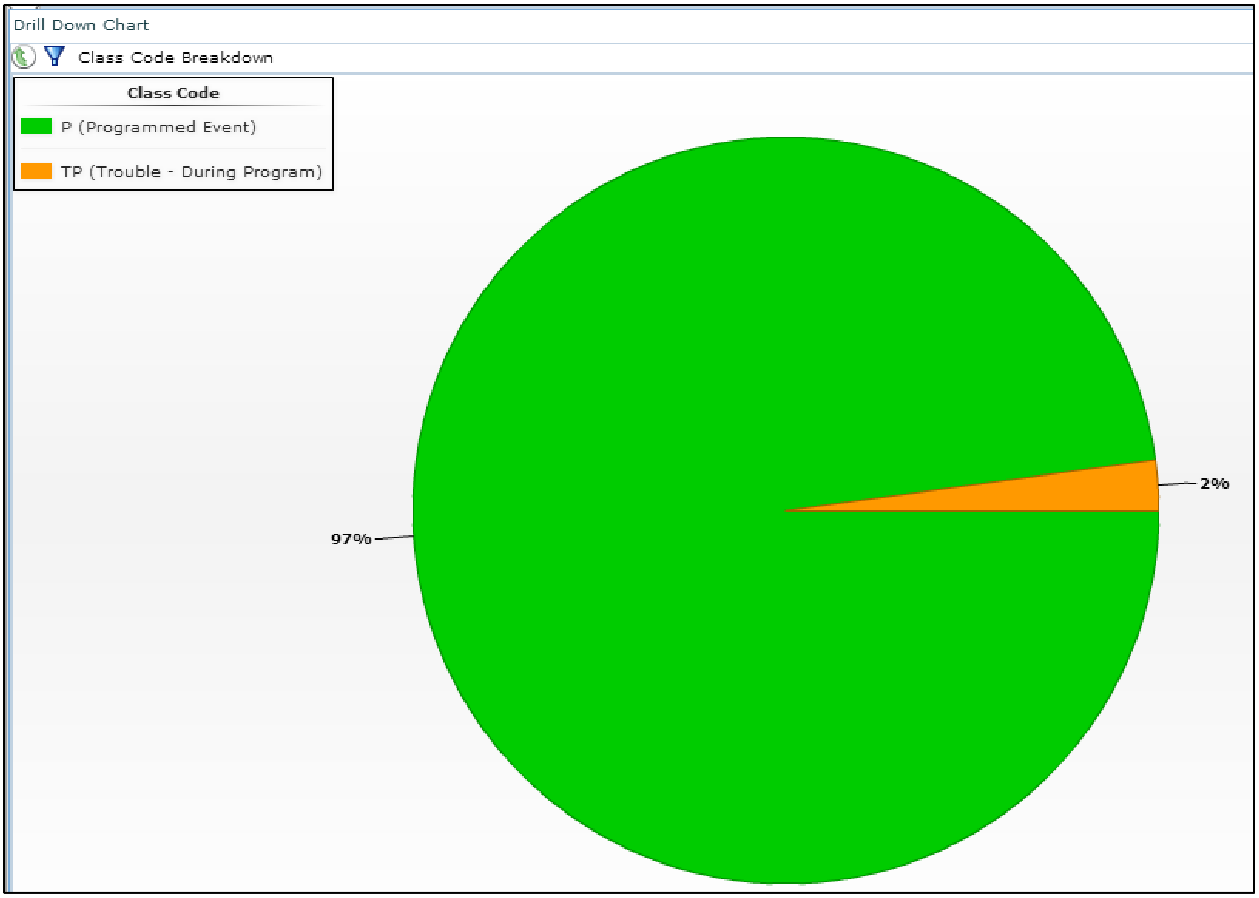

Figure 134: Oil Well #6; Percentage of Class Code Breakdowns

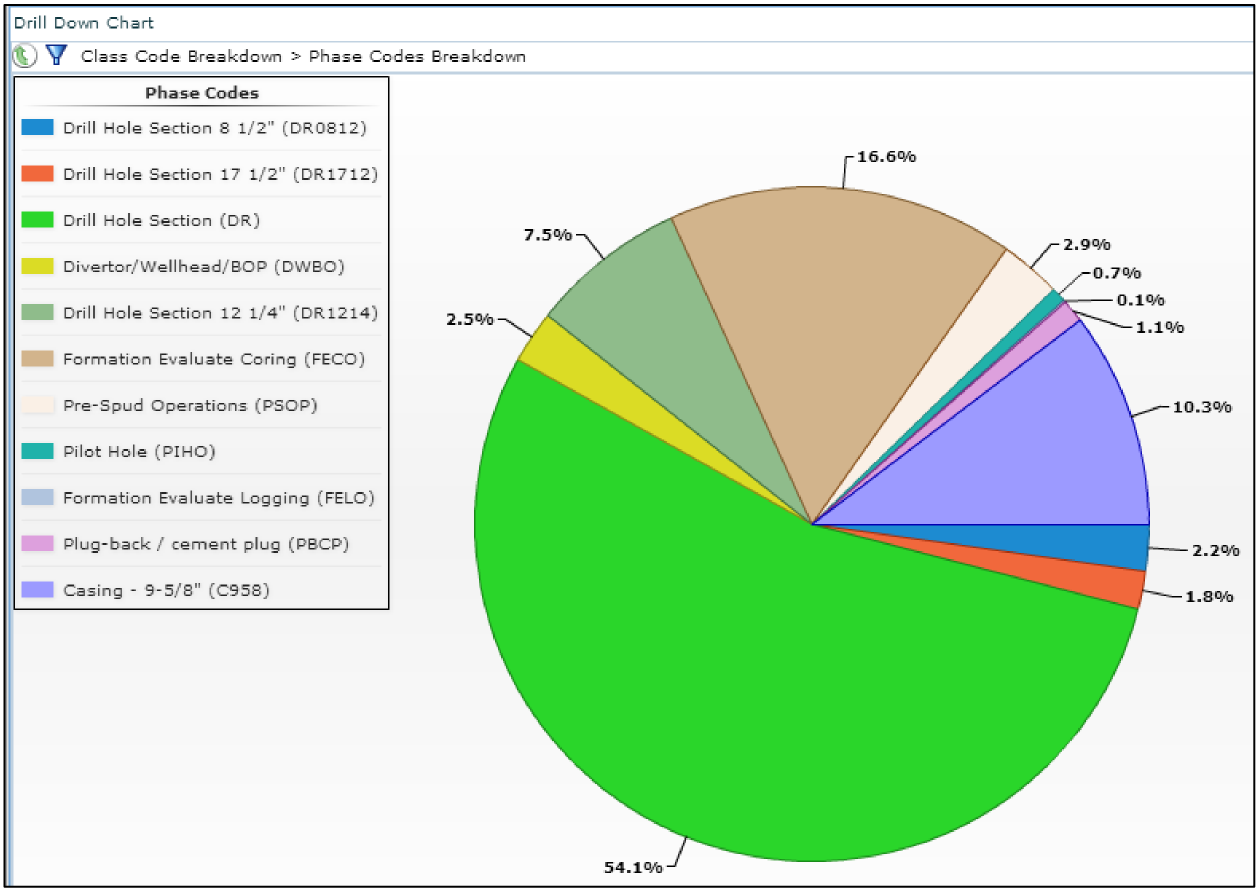

Figure 135: Oil Well #6; Percentage of Programmed Phase Code Breakdowns

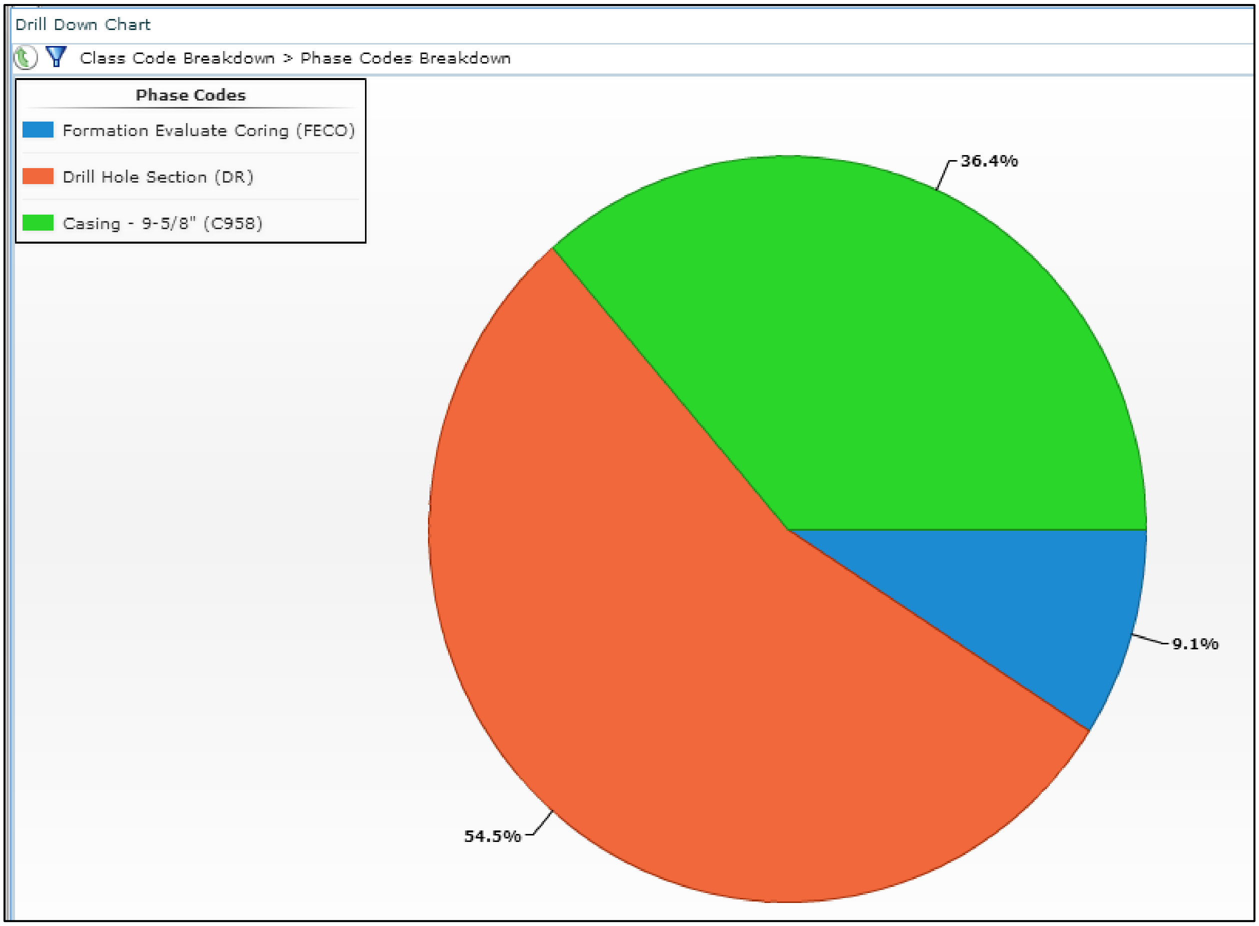

Figure 136: Oil Well #6; Percentage of Trouble during Programmed Breakdowns

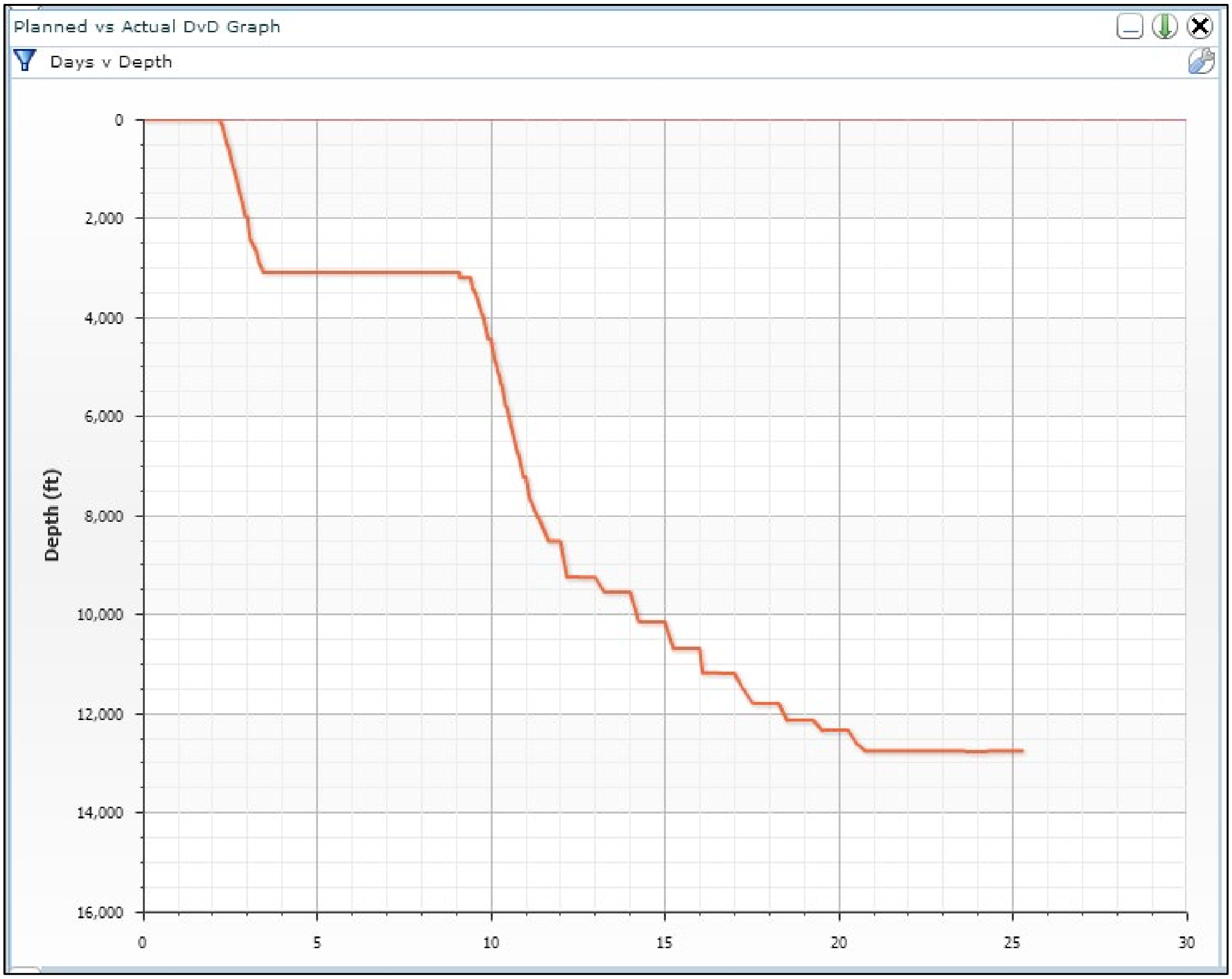

Figure 137: Oil Well #7; Days vs. Depth Drilled

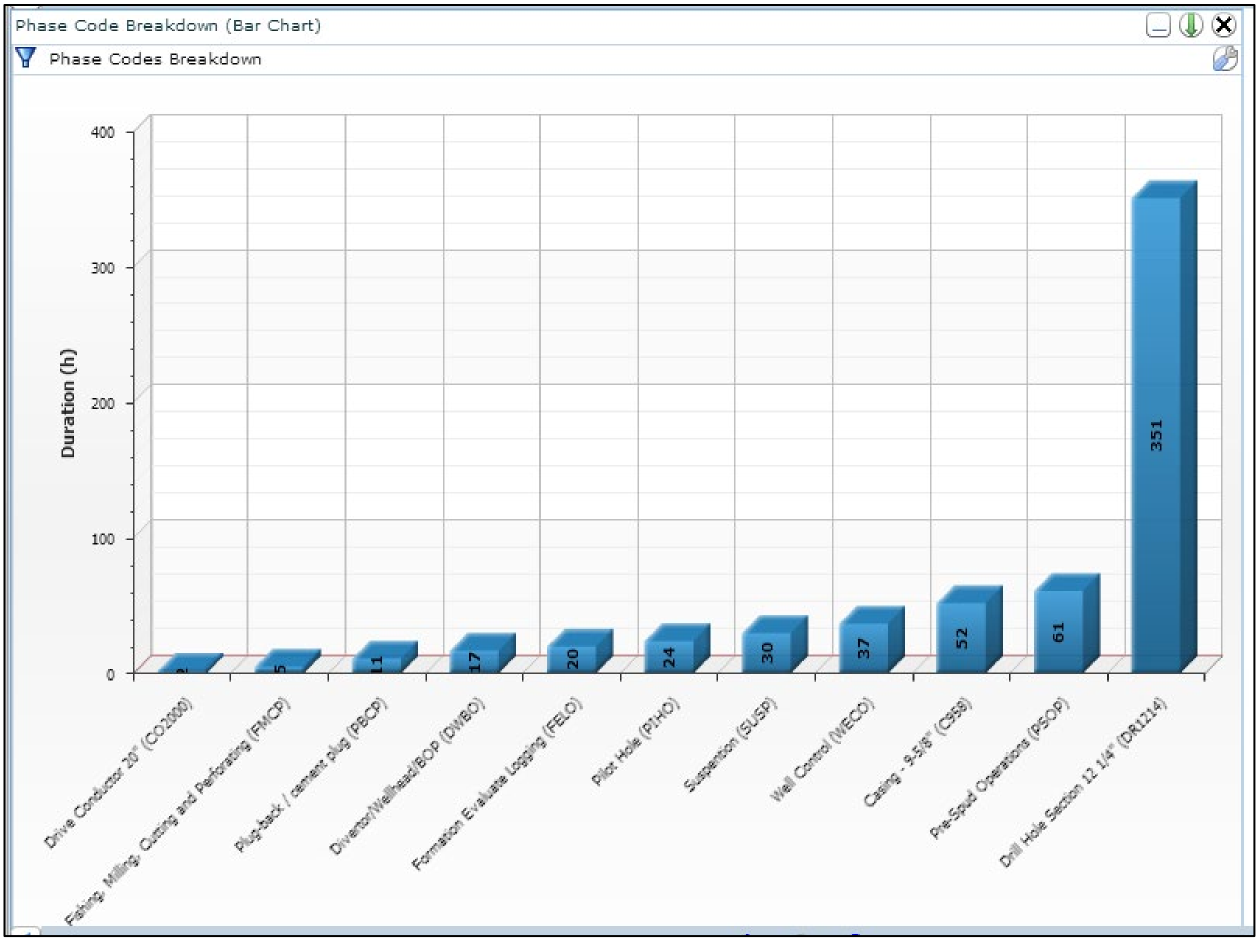

Figure 138: Oil Well #7; Phase Code Breakdown

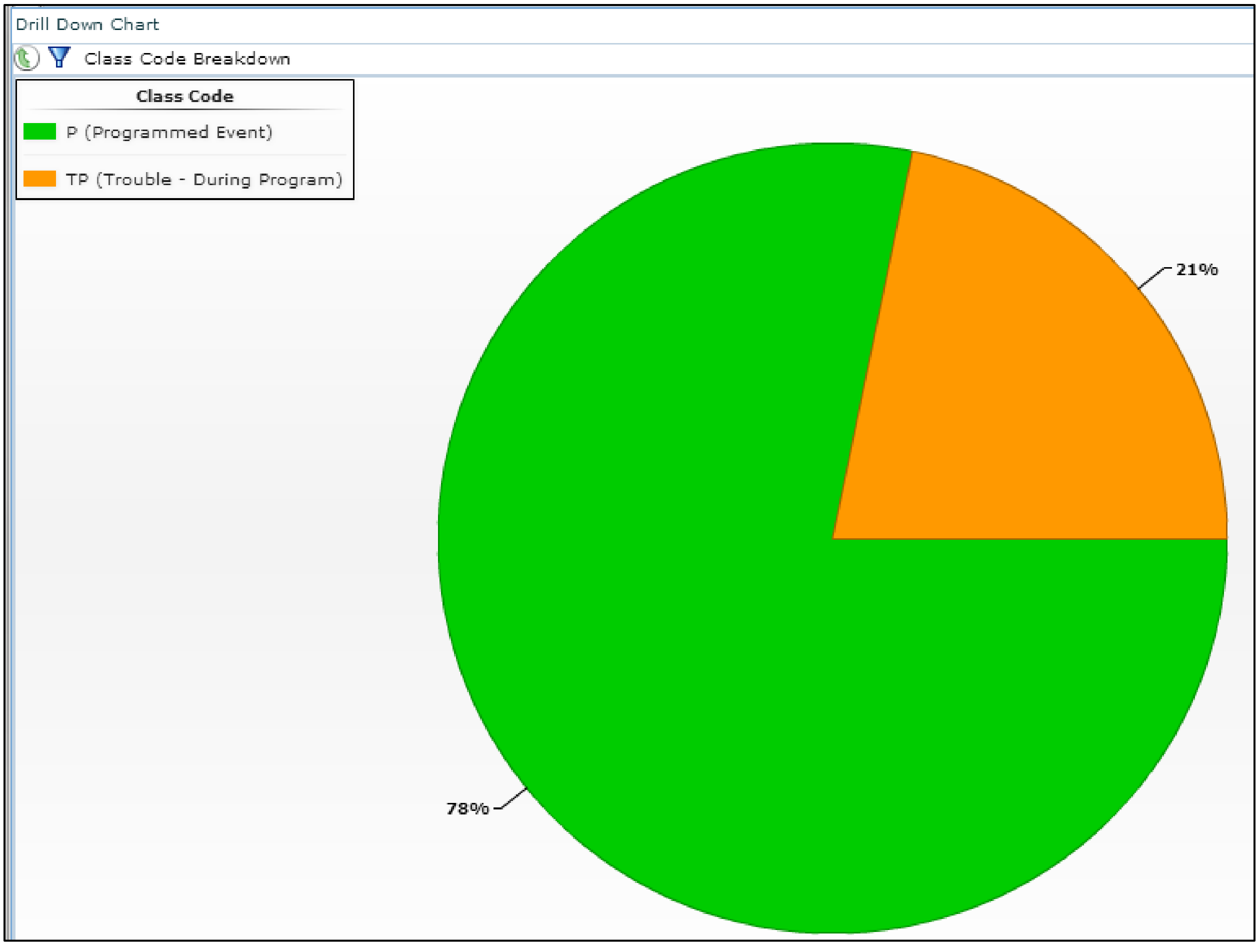

Figure 139: Oil Well #7; Percentage of Class Code Breakdowns

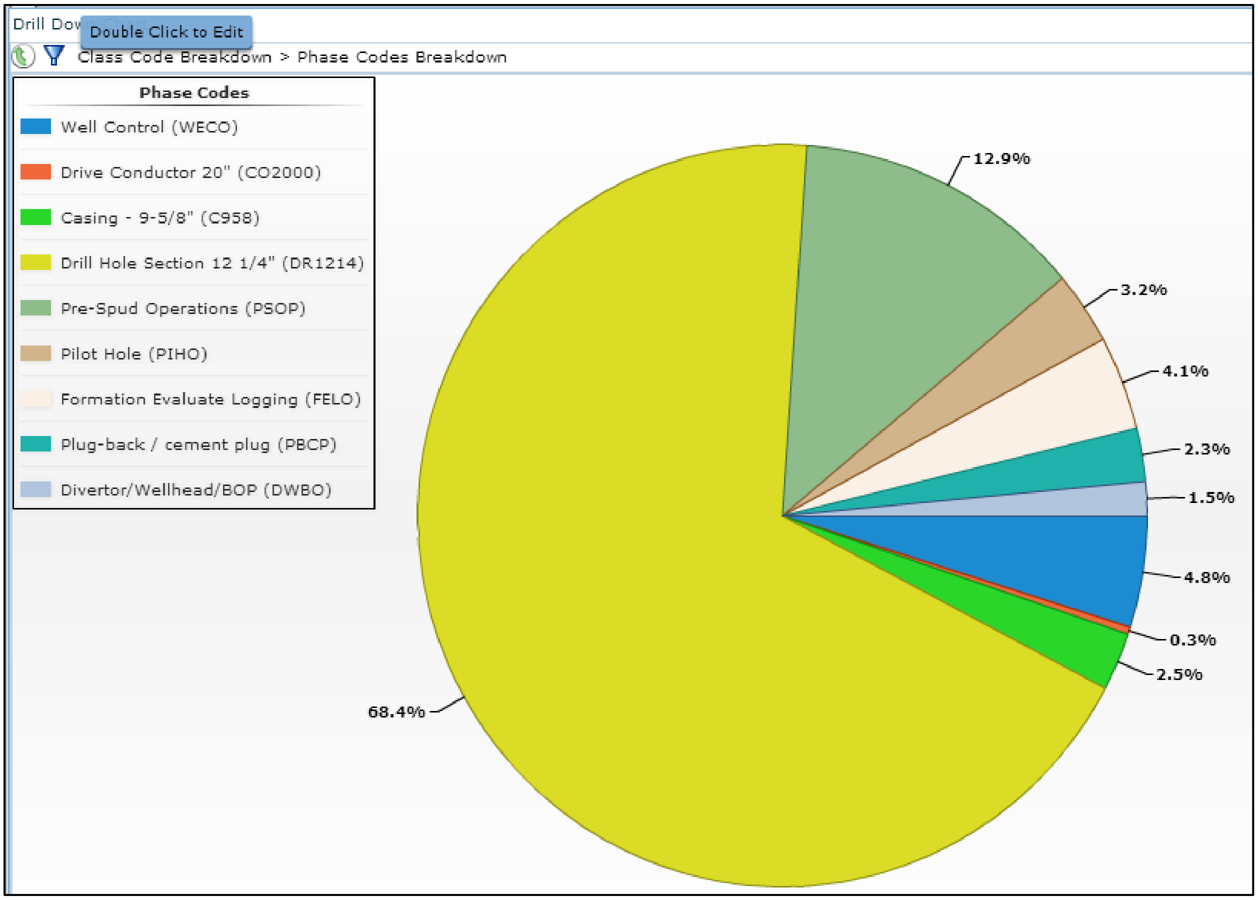

Figure 140: Oil Well #7; Percentage of Programmed Phase Code Breakdowns

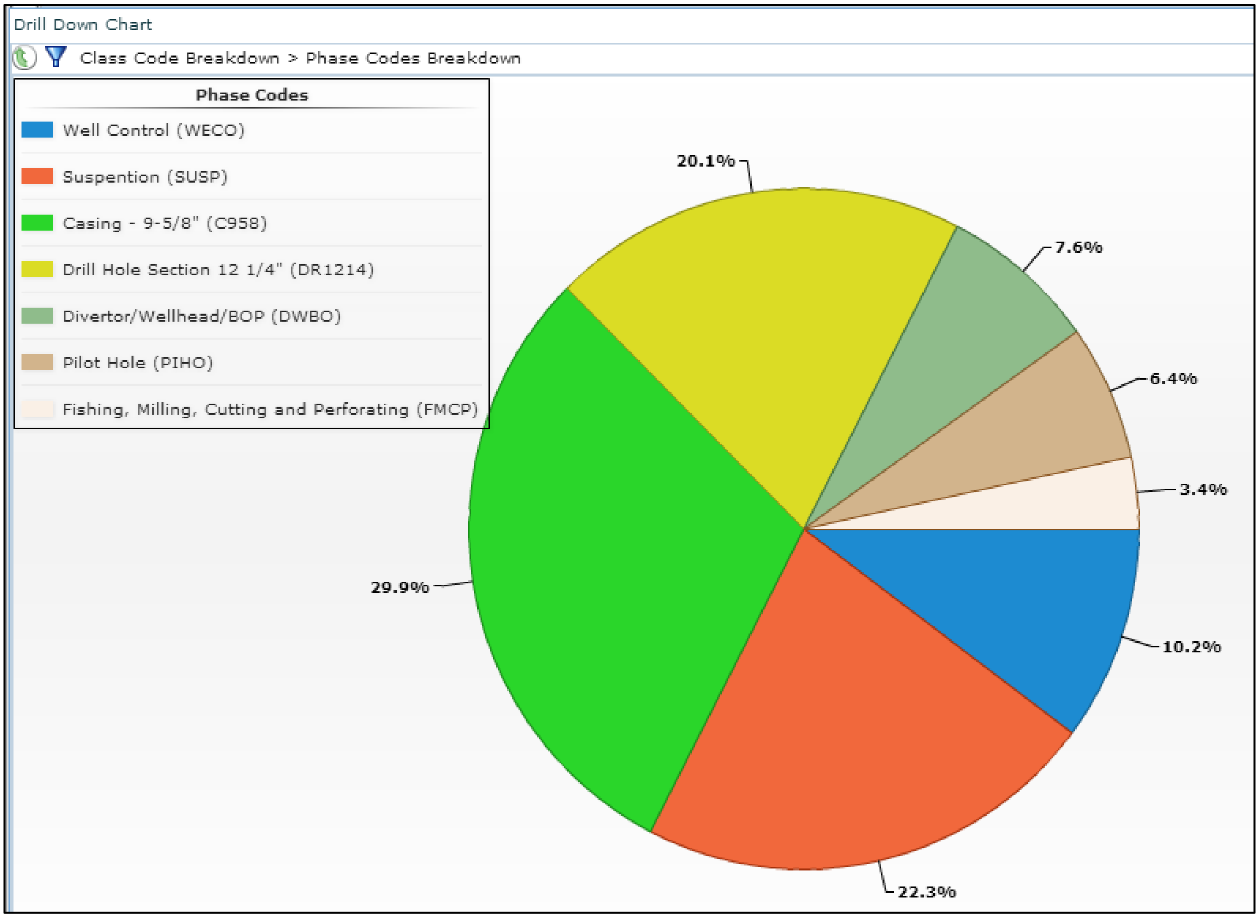

Figure 141: Oil Well #7; Percentage of Trouble during Programmed Code Breakdowns

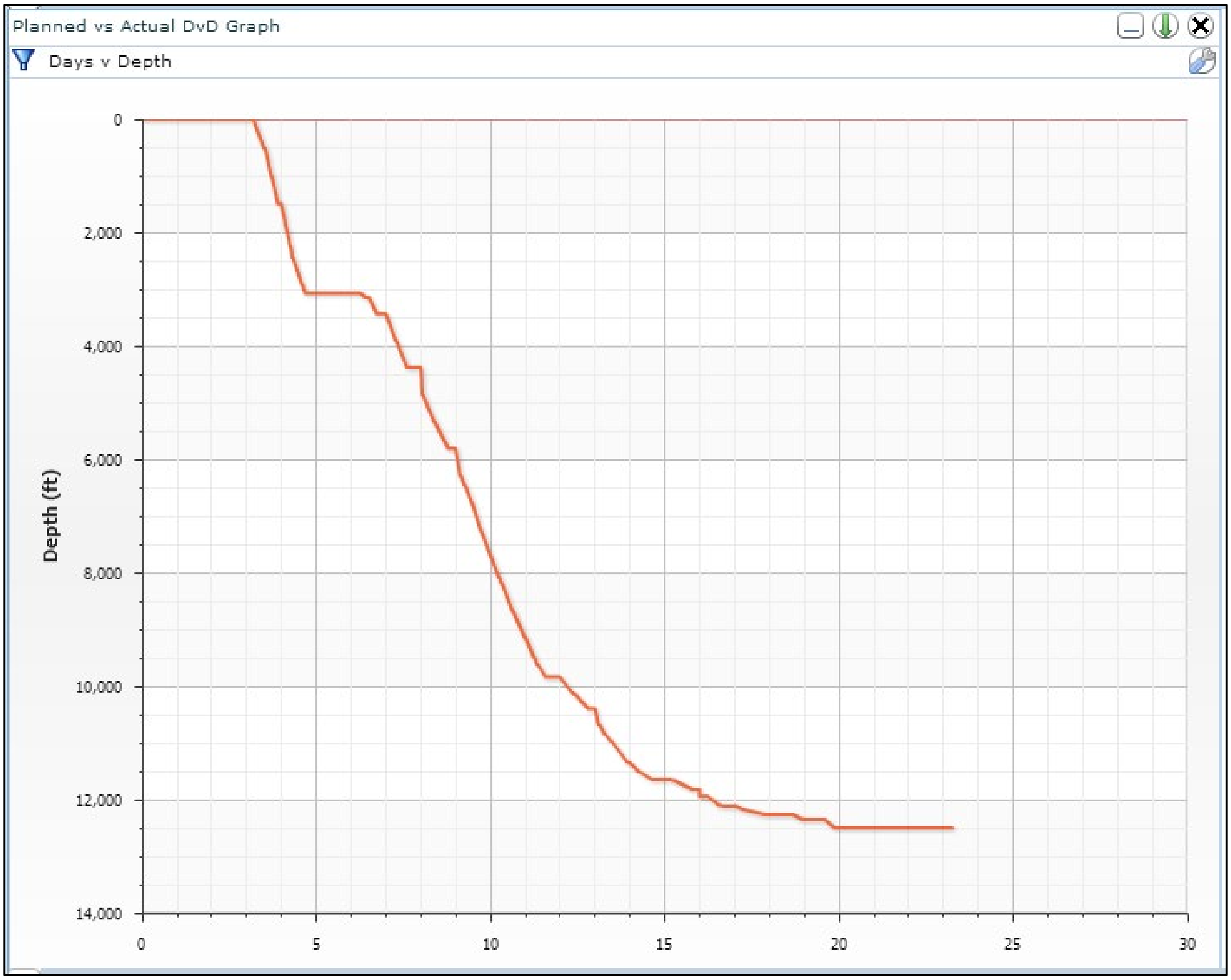

Figure 142: Oil Well #8; Days vs. Depth Drilled

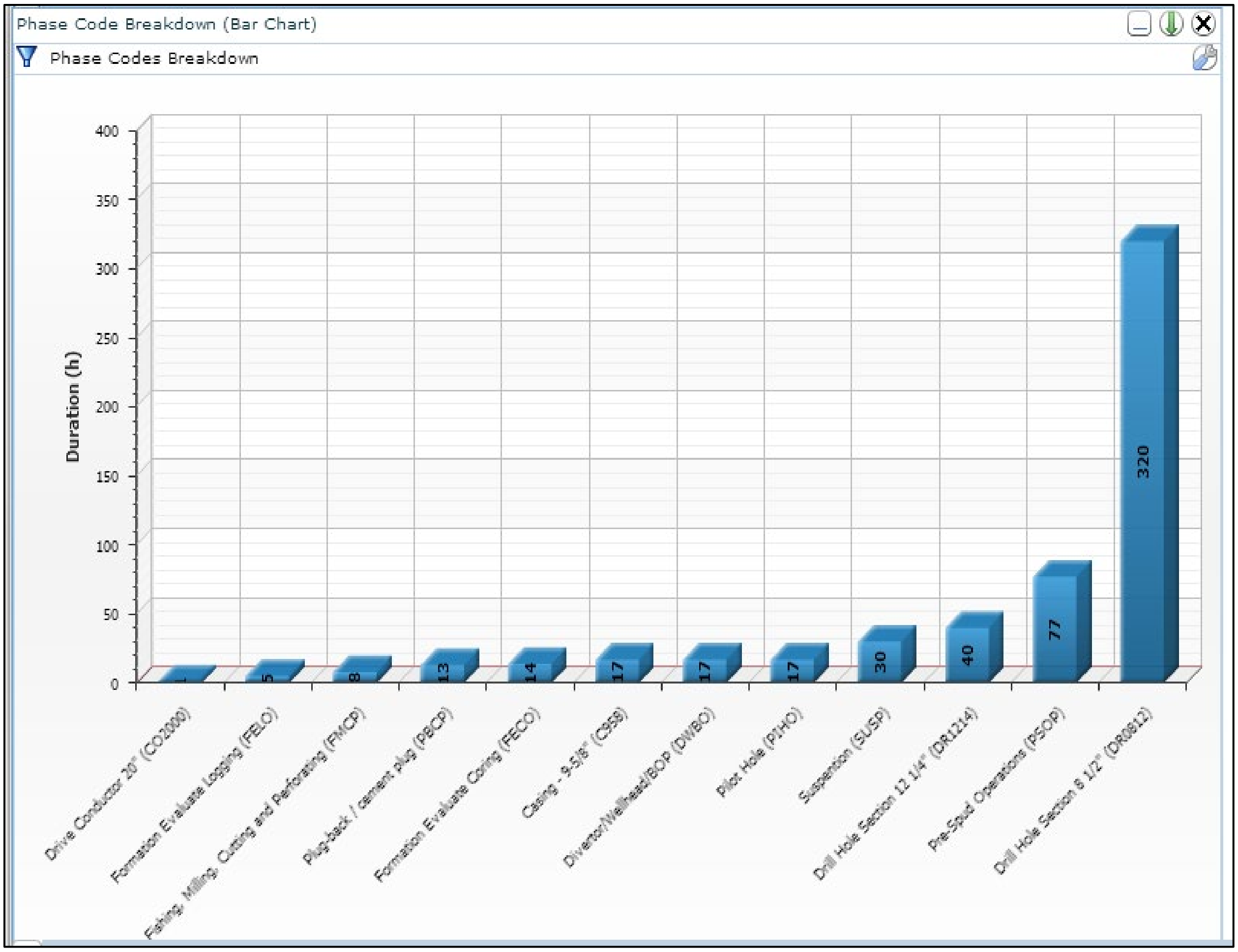

Figure 143: Oil Well #8; Phase Code Breakdown

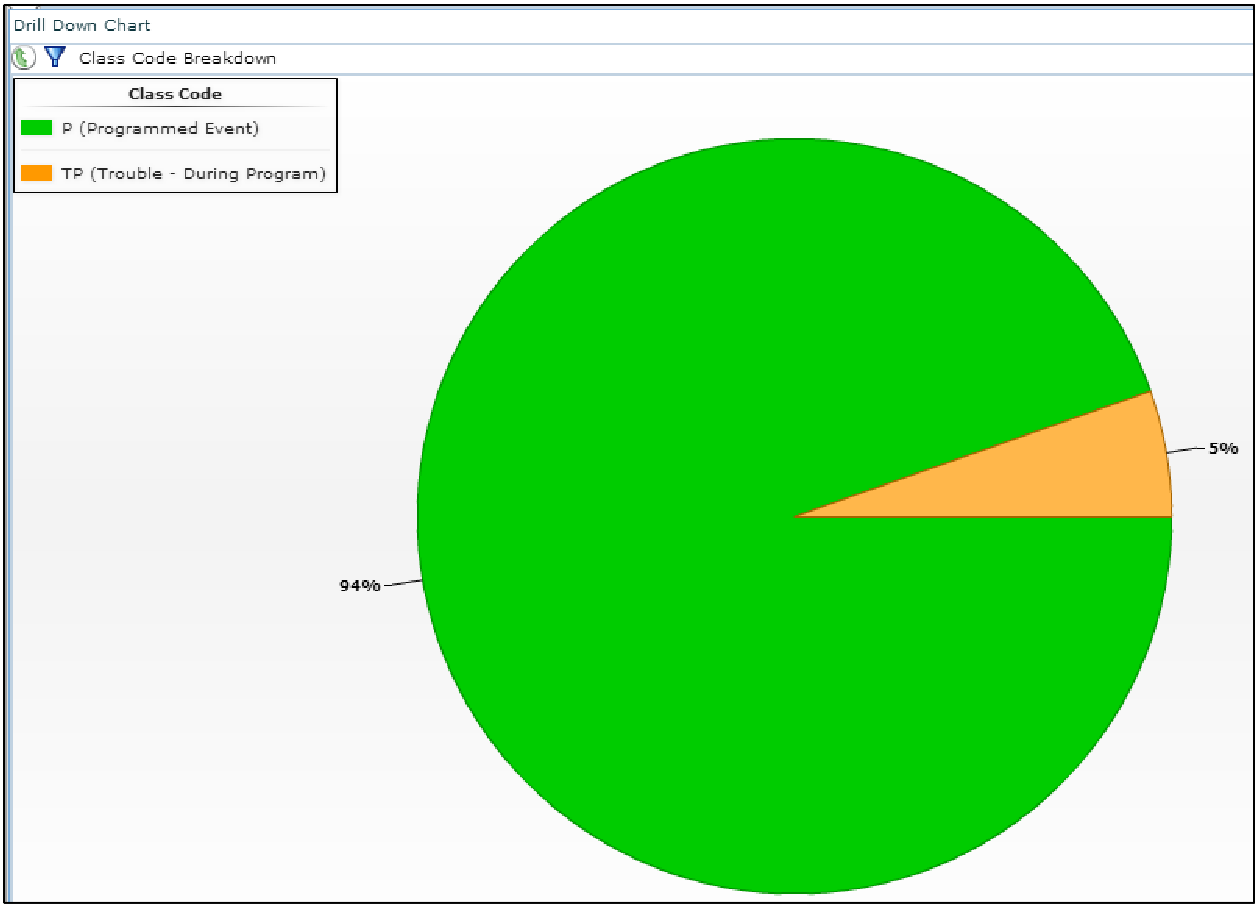

Figure 144: Oil Well #8; Percentage of Class Code Breakdowns

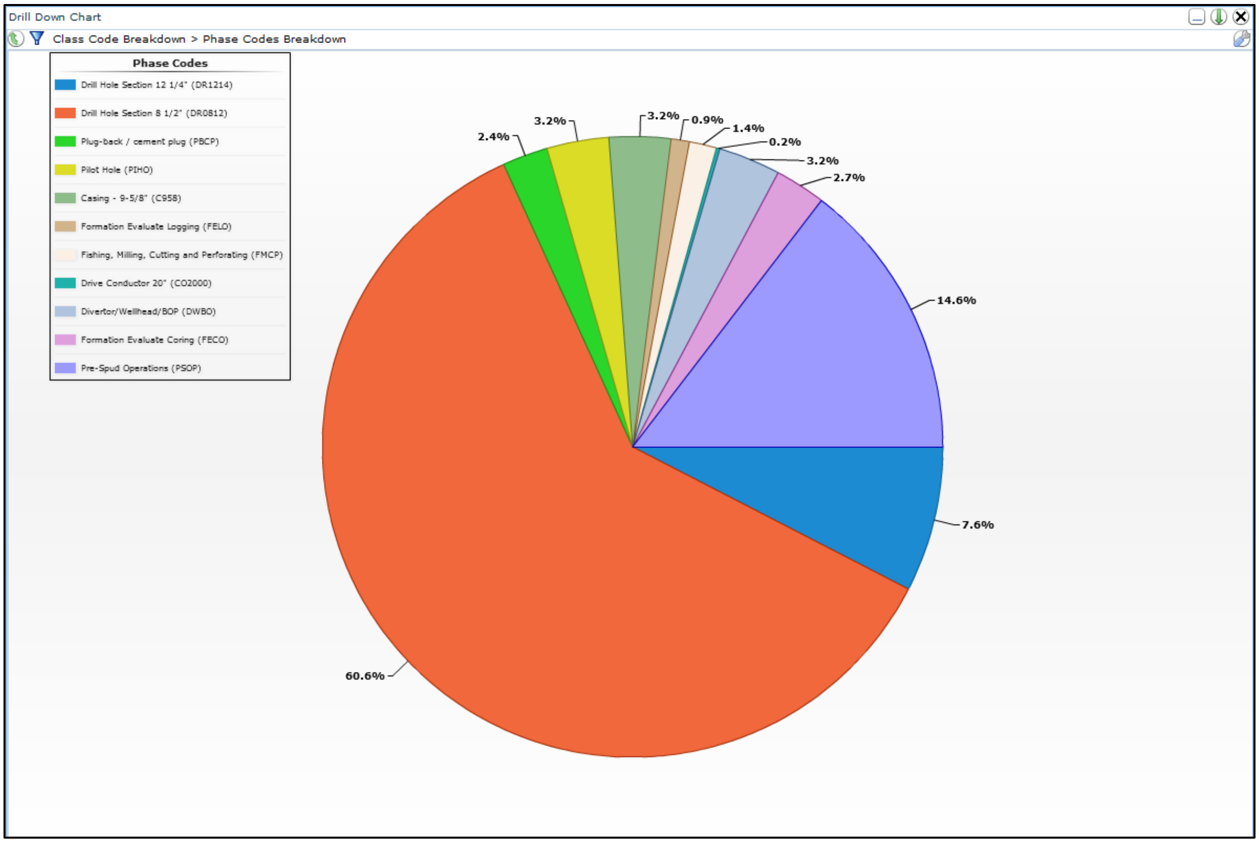

Figure 145: Oil Well #8; Percentage of Programmed Phase Code Breakdowns

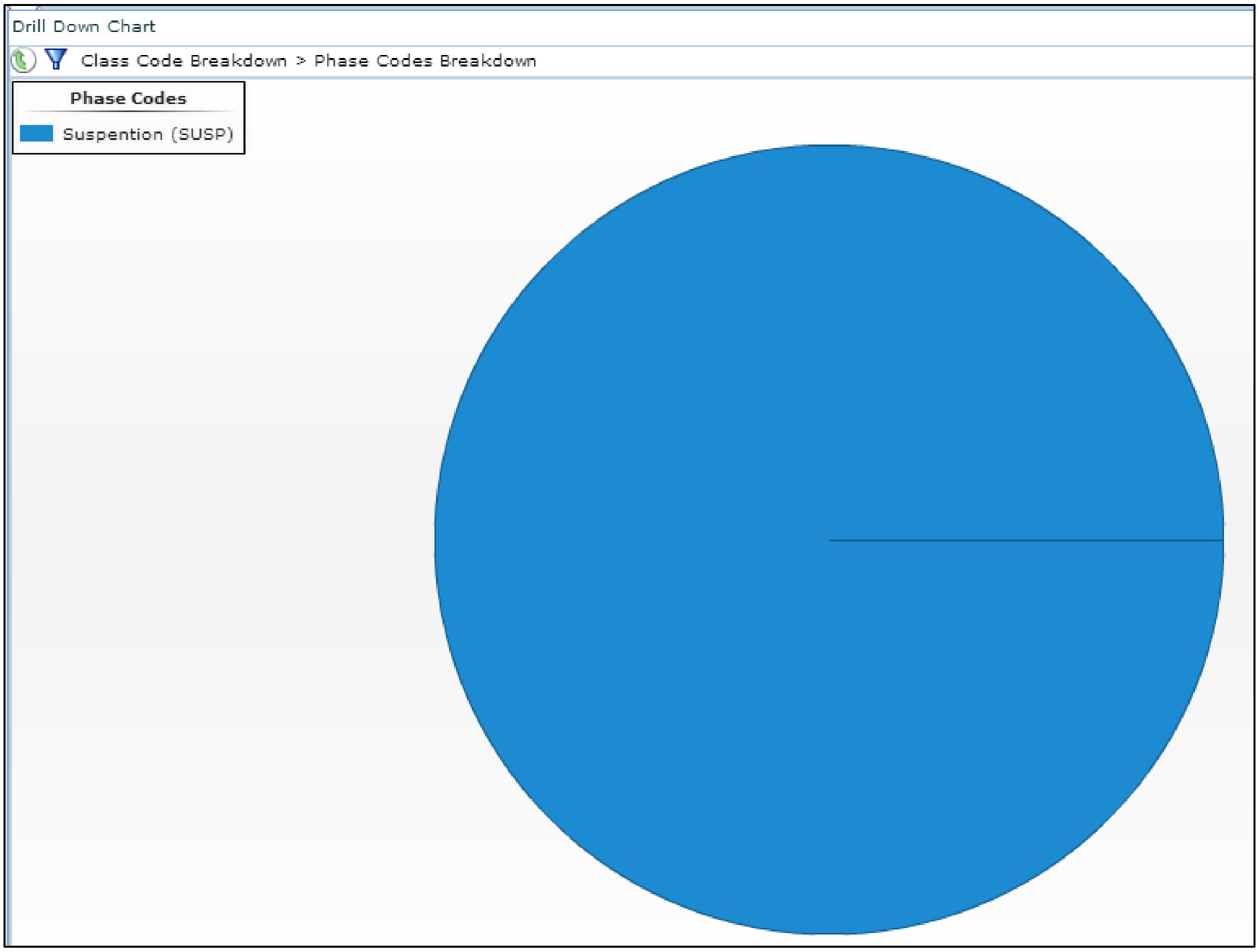

Figure 146: Oil Well #8; Percentage of Trouble during Programmed Phase Code Breakdowns

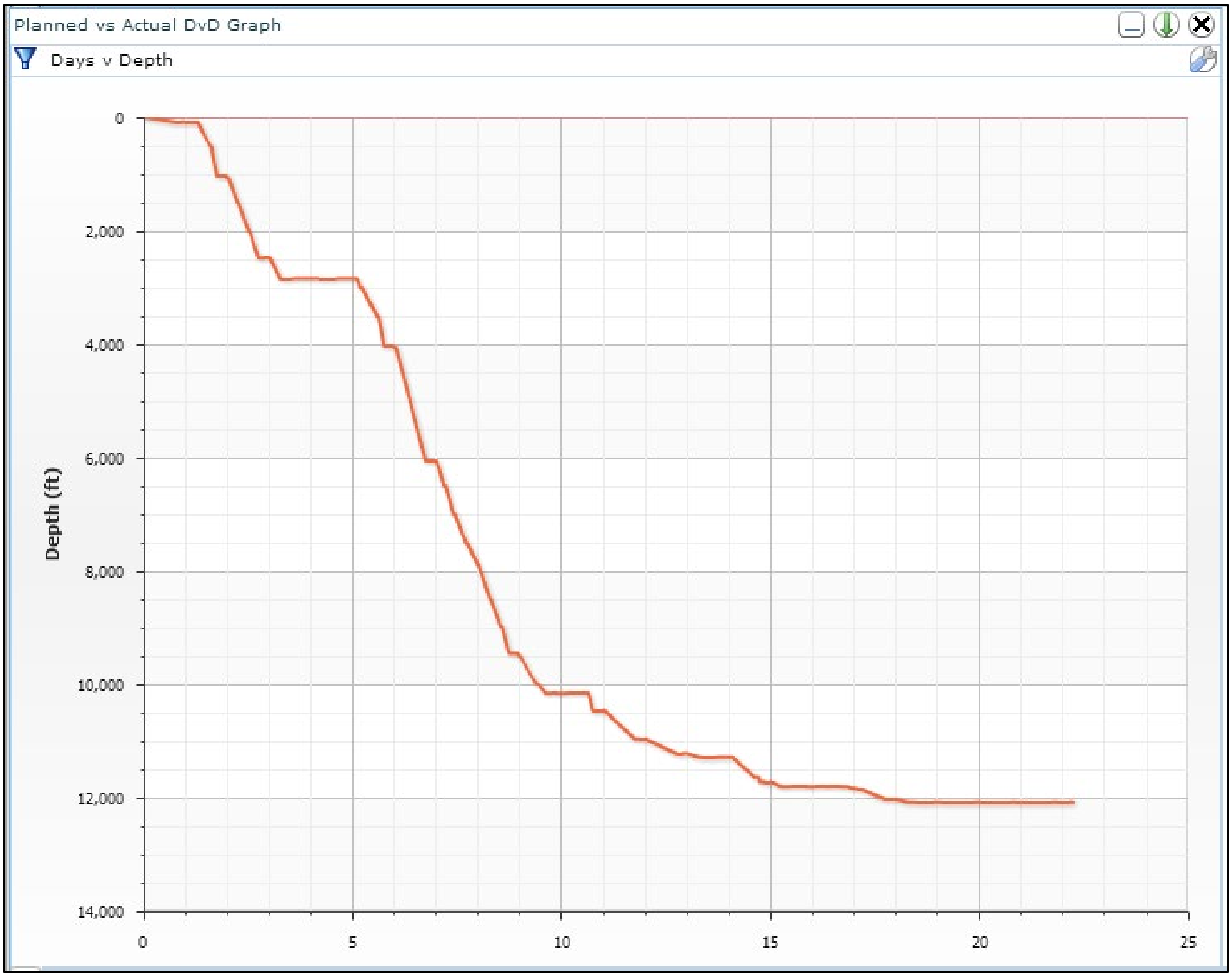

Figure 147: Oil Well #9; Days vs. Depth Drilled

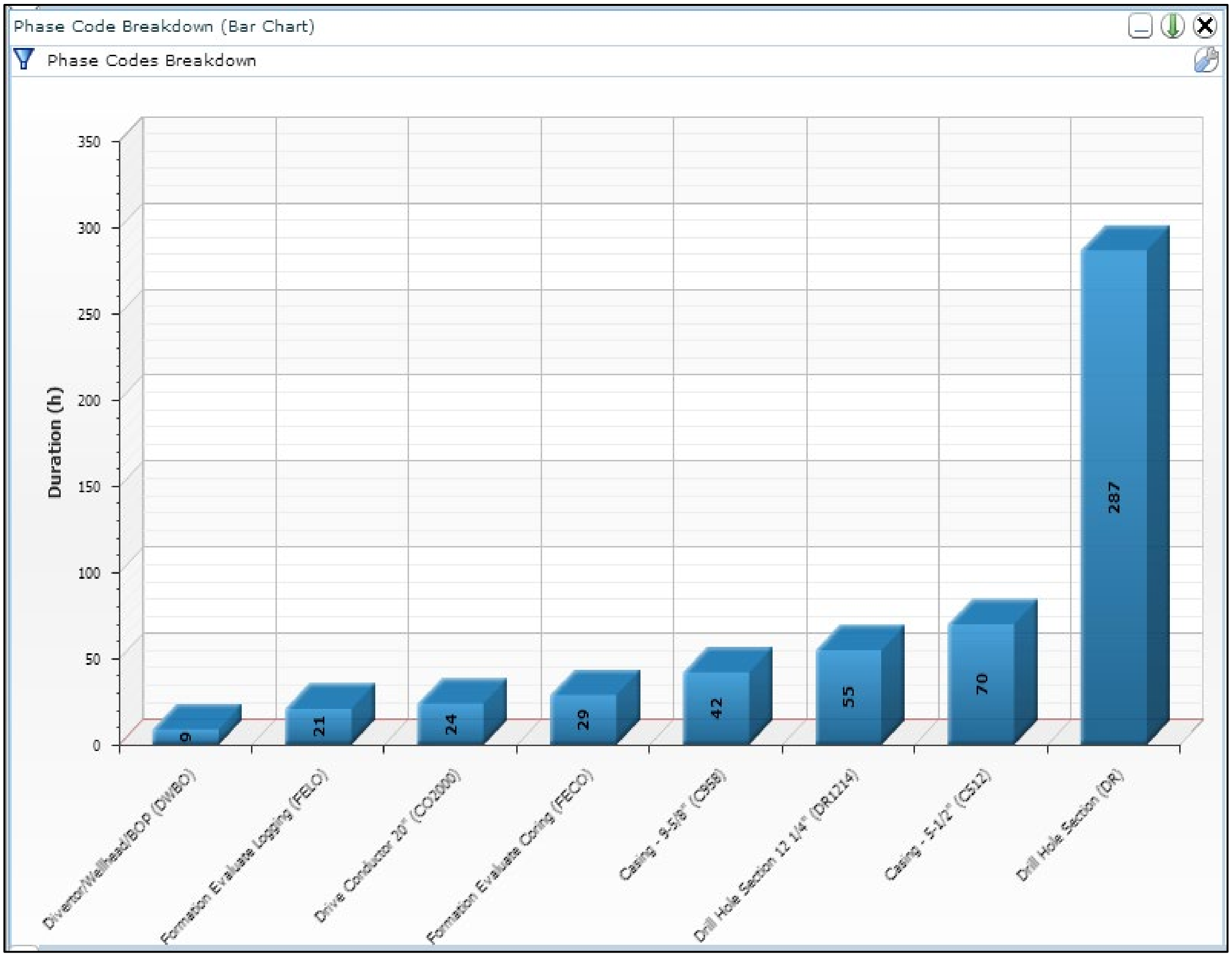

Figure 148: Oil Well #9; Phase Code Breakdown

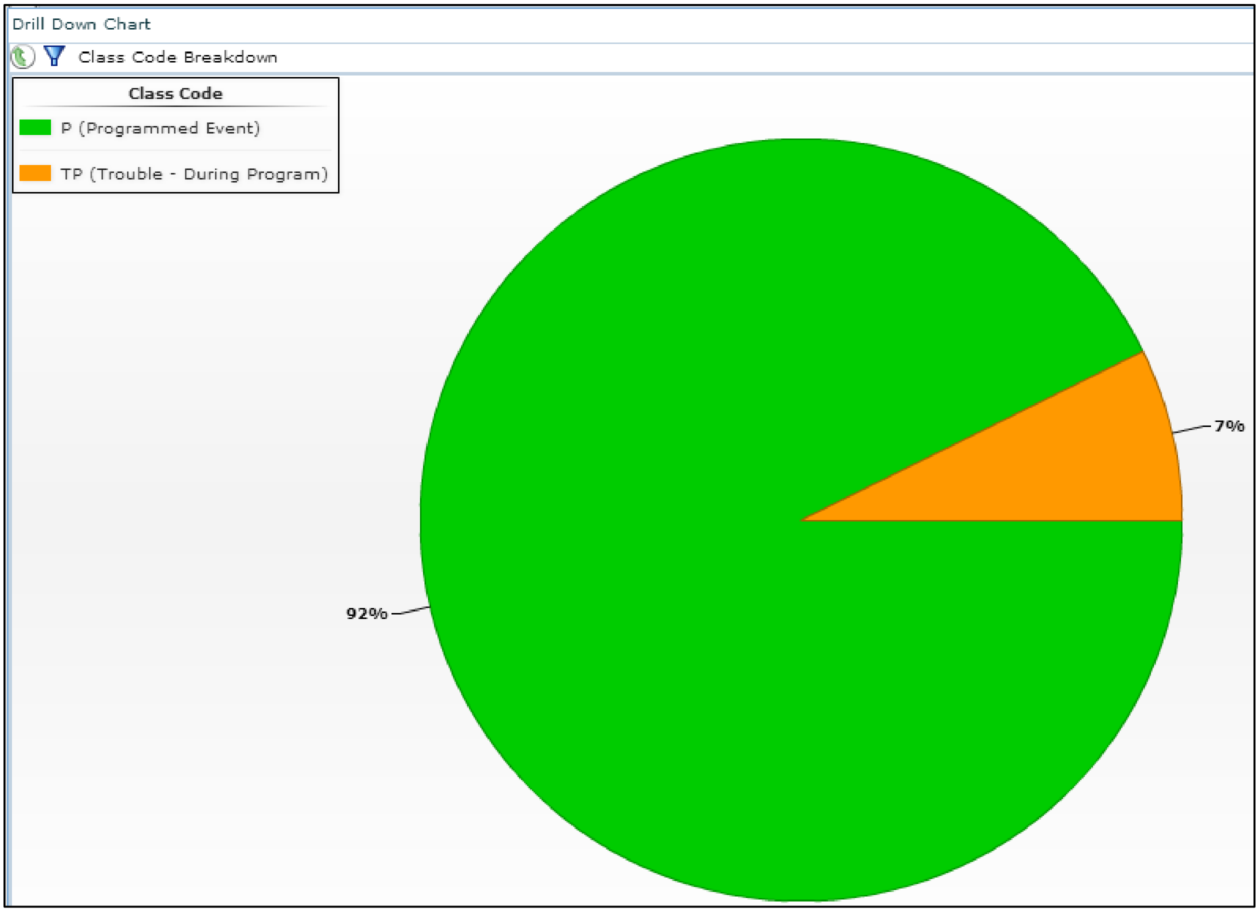

Figure 149: Oil Well #9; Percentage of Class Code Breakdowns

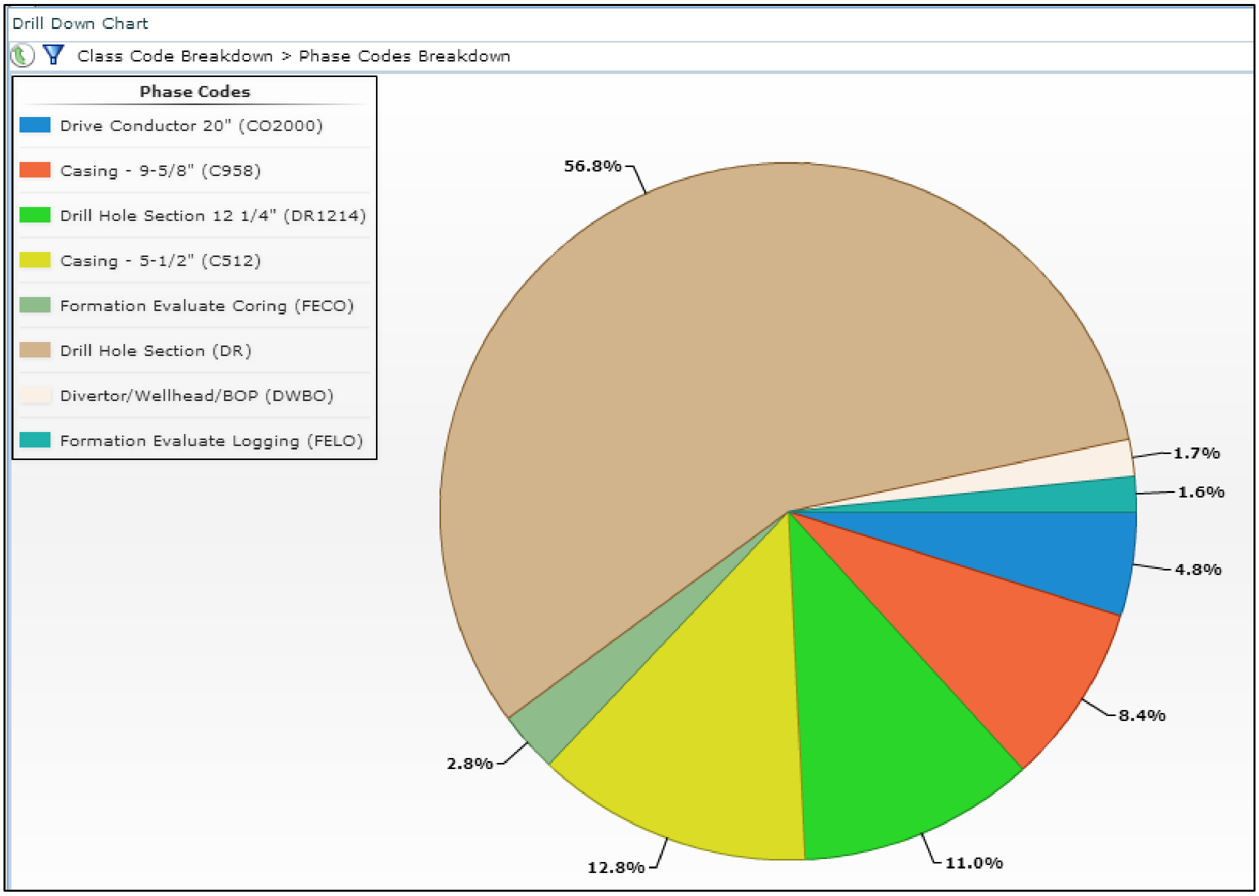

Figure 150: Oil Well #9; Percentage of Programmed Phase Code Breakdowns

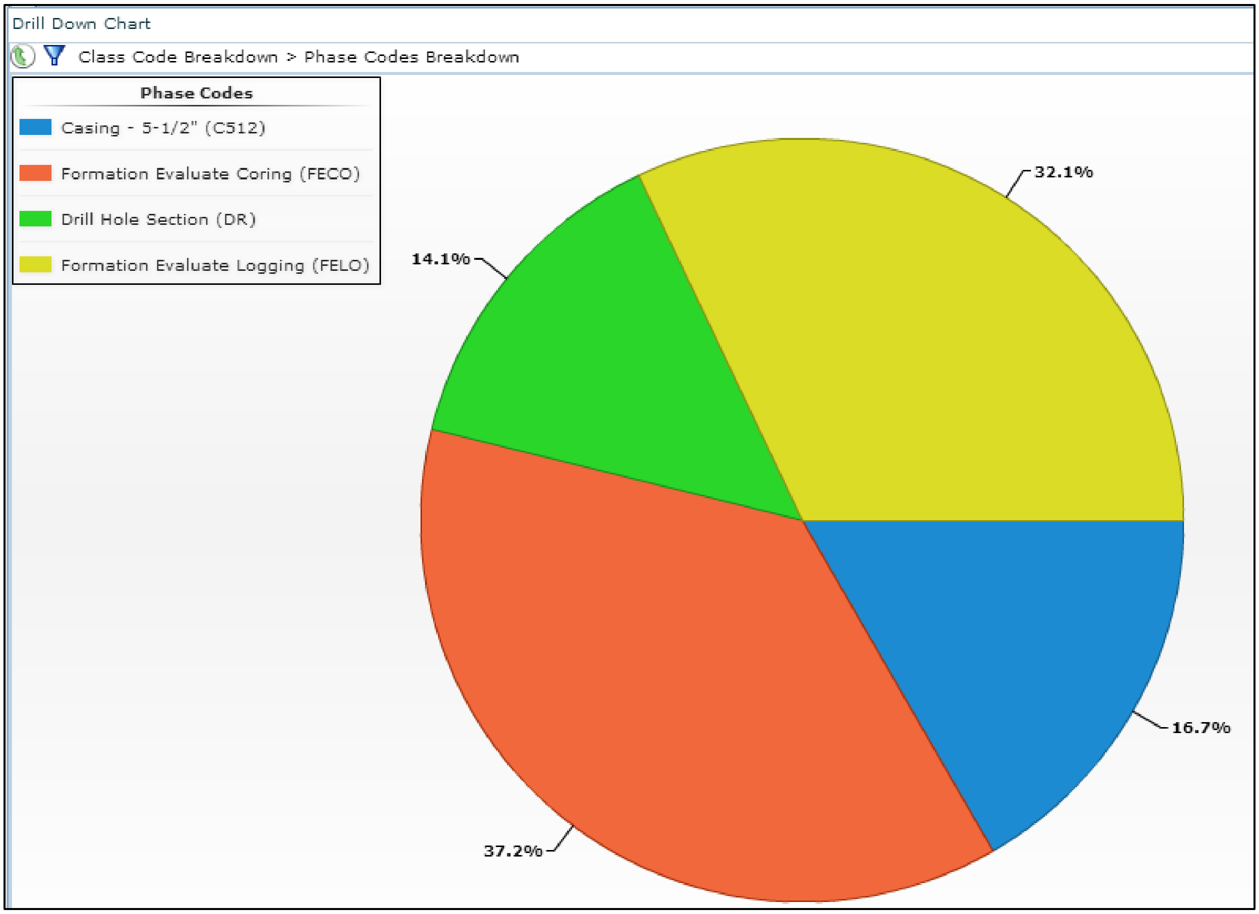

Figure 151: Oil Well #9; Percentage of Trouble during Phase Code Breakdowns

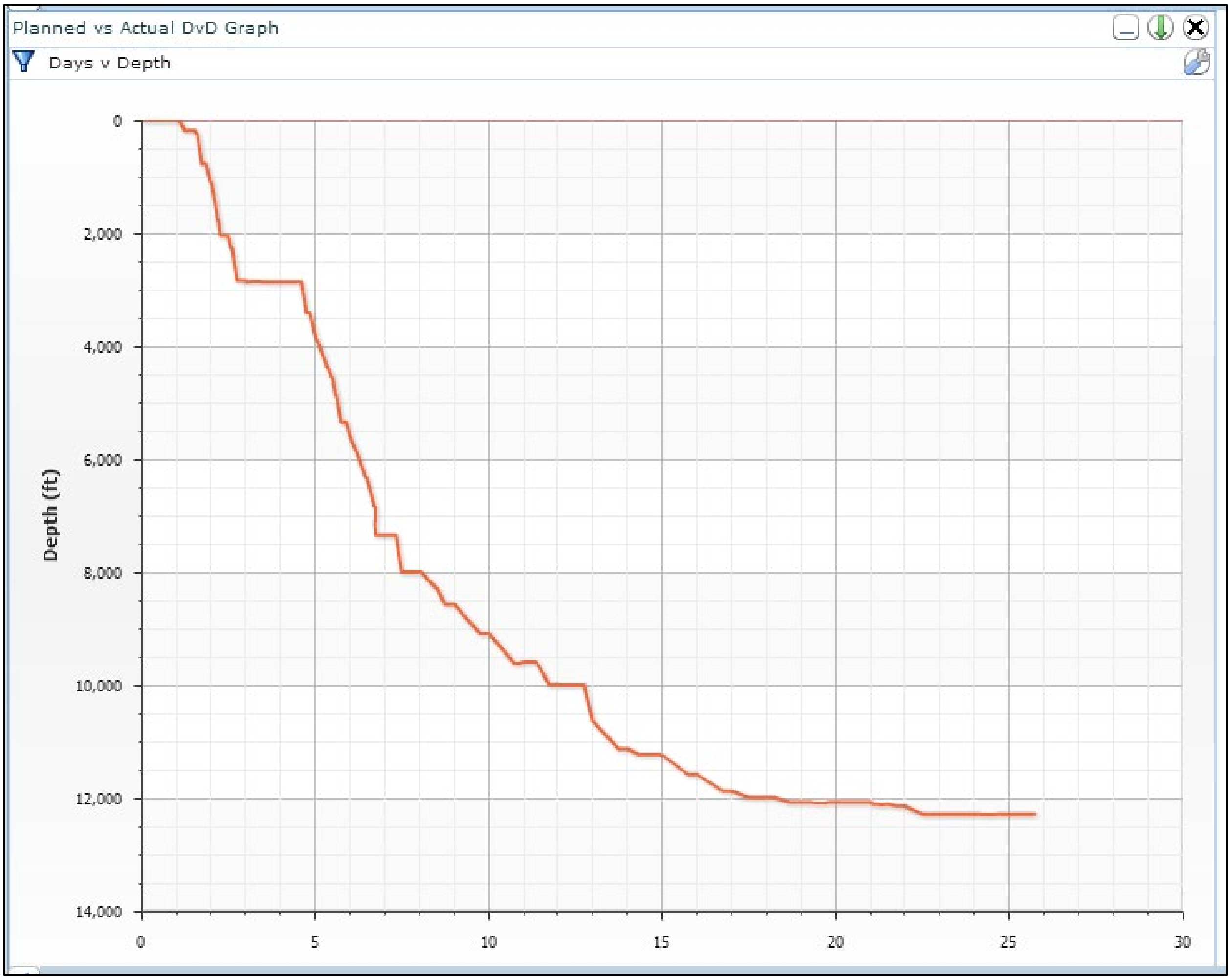

Figure 152: Oil Well #10; Days vs. Depth Drilled

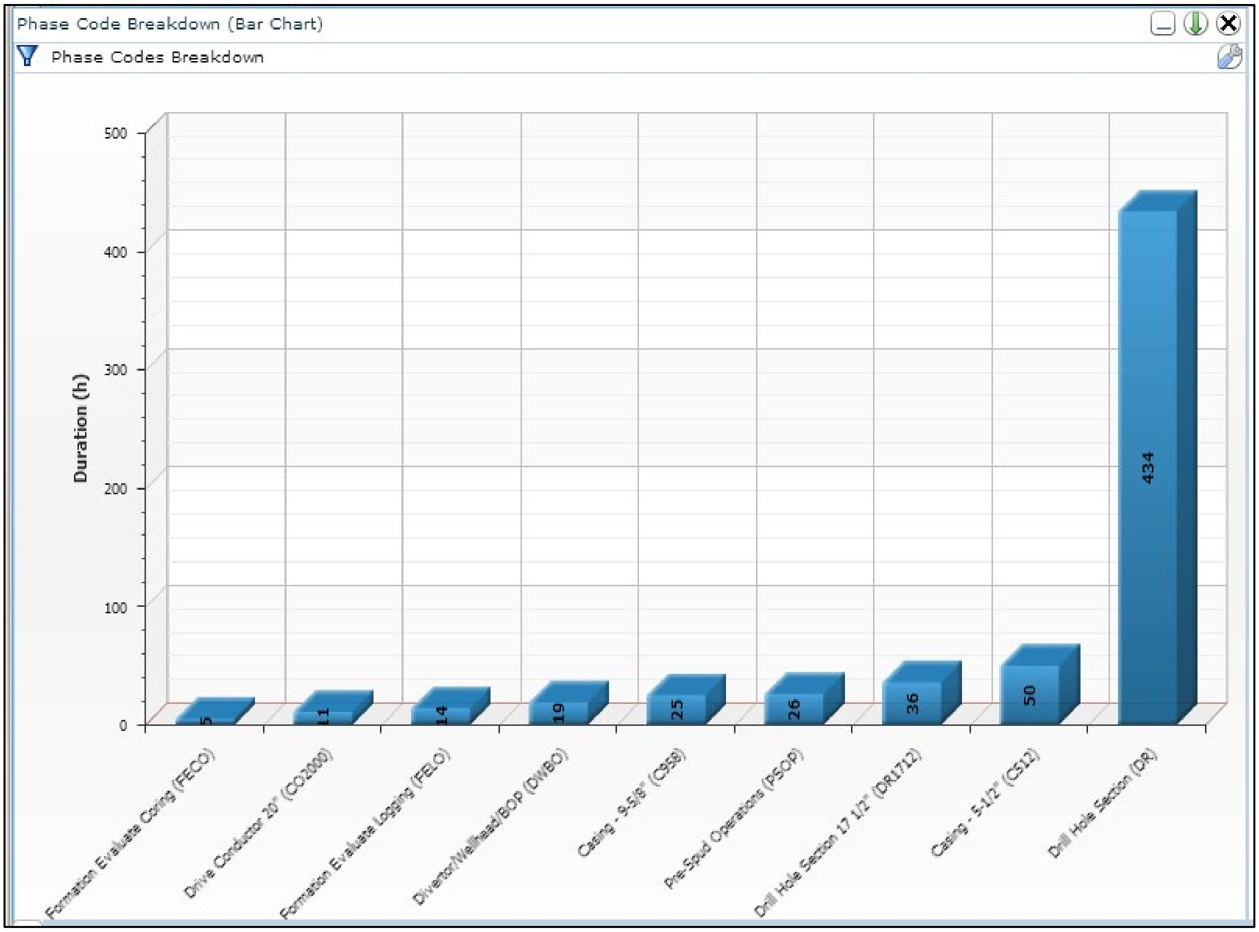

Figure 153: Oil Well #10; Phase Code Breakdown

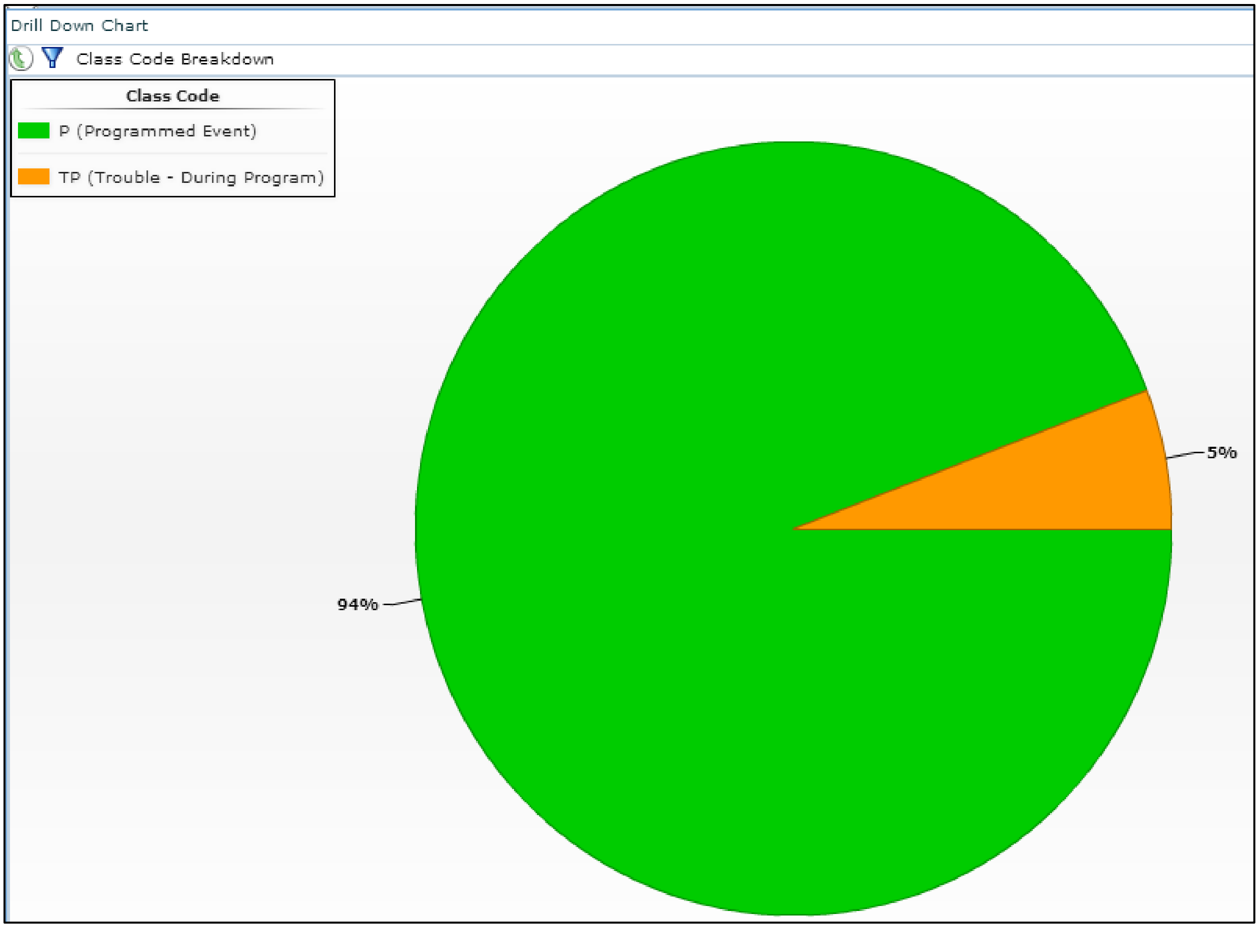

Figure 154: Oil Well #10; Percentage of Class Code Breakdowns

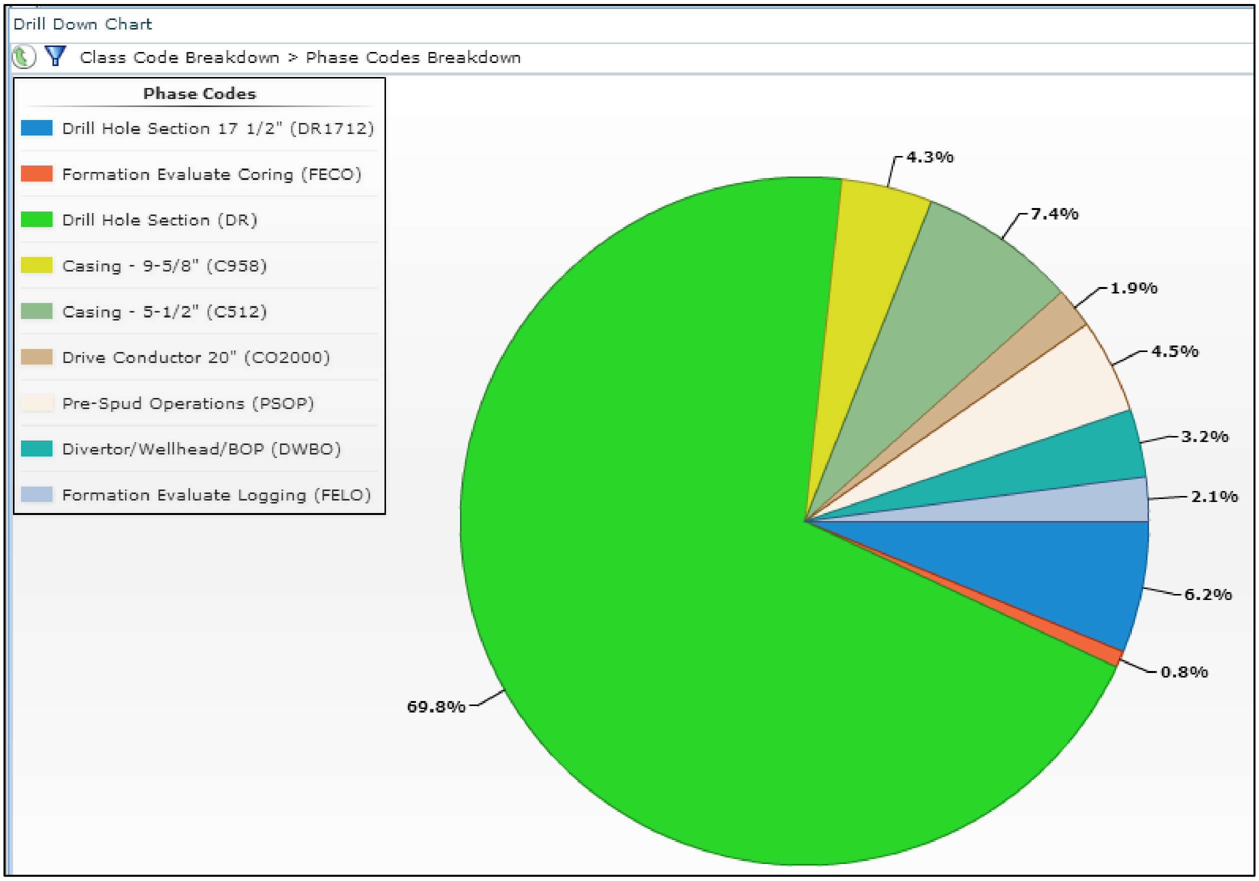

Figure 155: Oil Well #10; Percentage of Programmed Phase Code Breakdowns

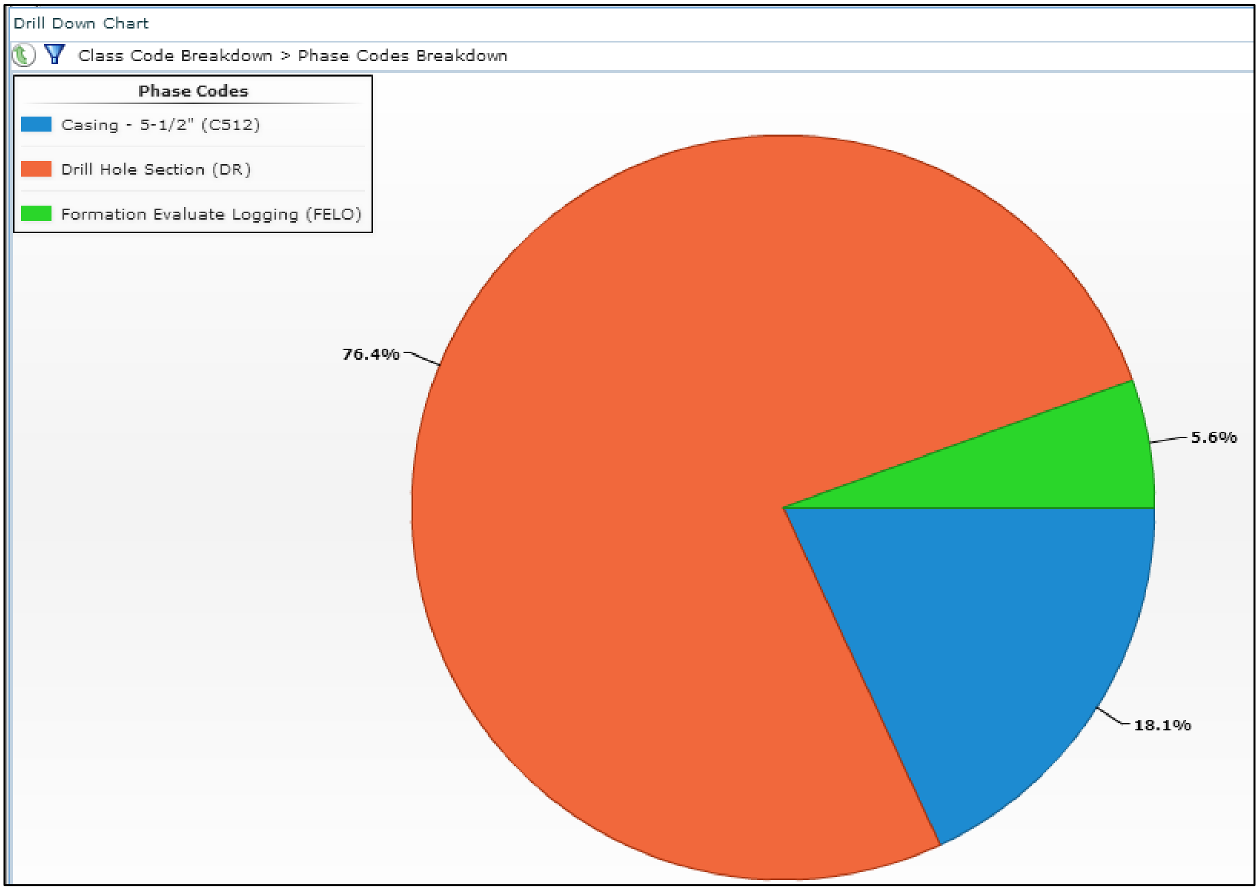

Figure 156: Oil Well #10; Percentage of Trouble during Programmed Phase Code Breakdowns

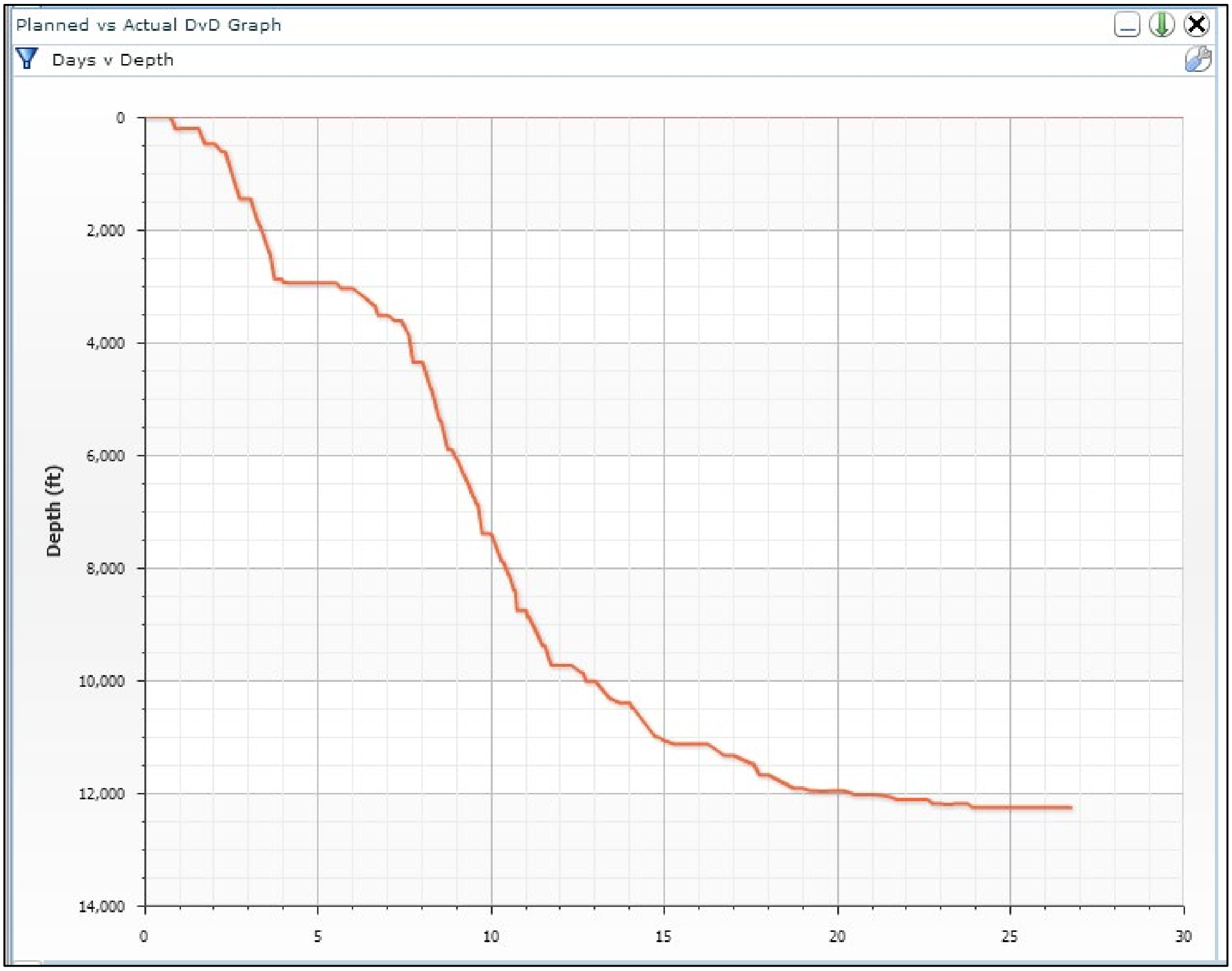

Figure 157: Oil Well #11; Days vs. Depth Drilled

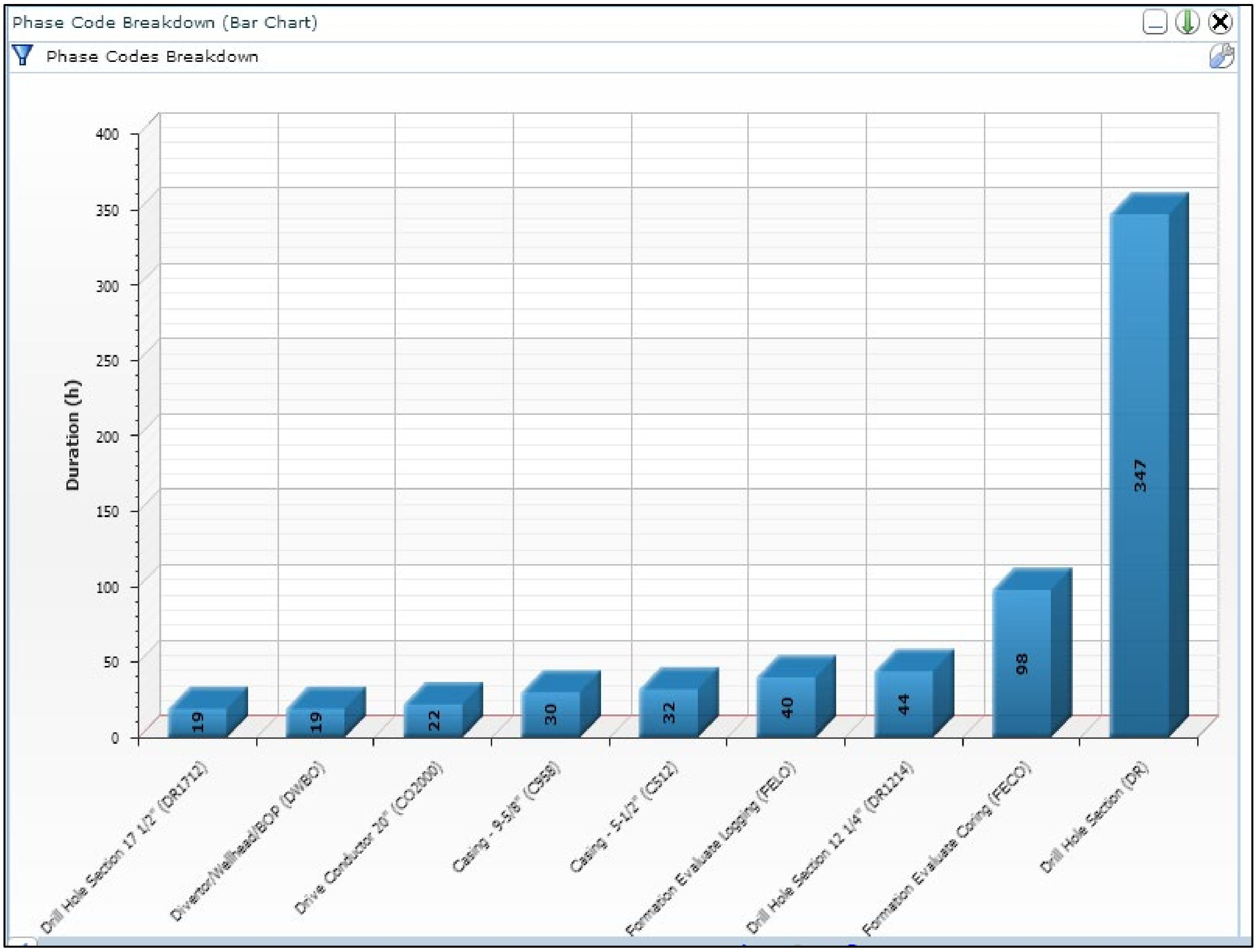

Figure 158: Oil Well #11; Phase Code Breakdown

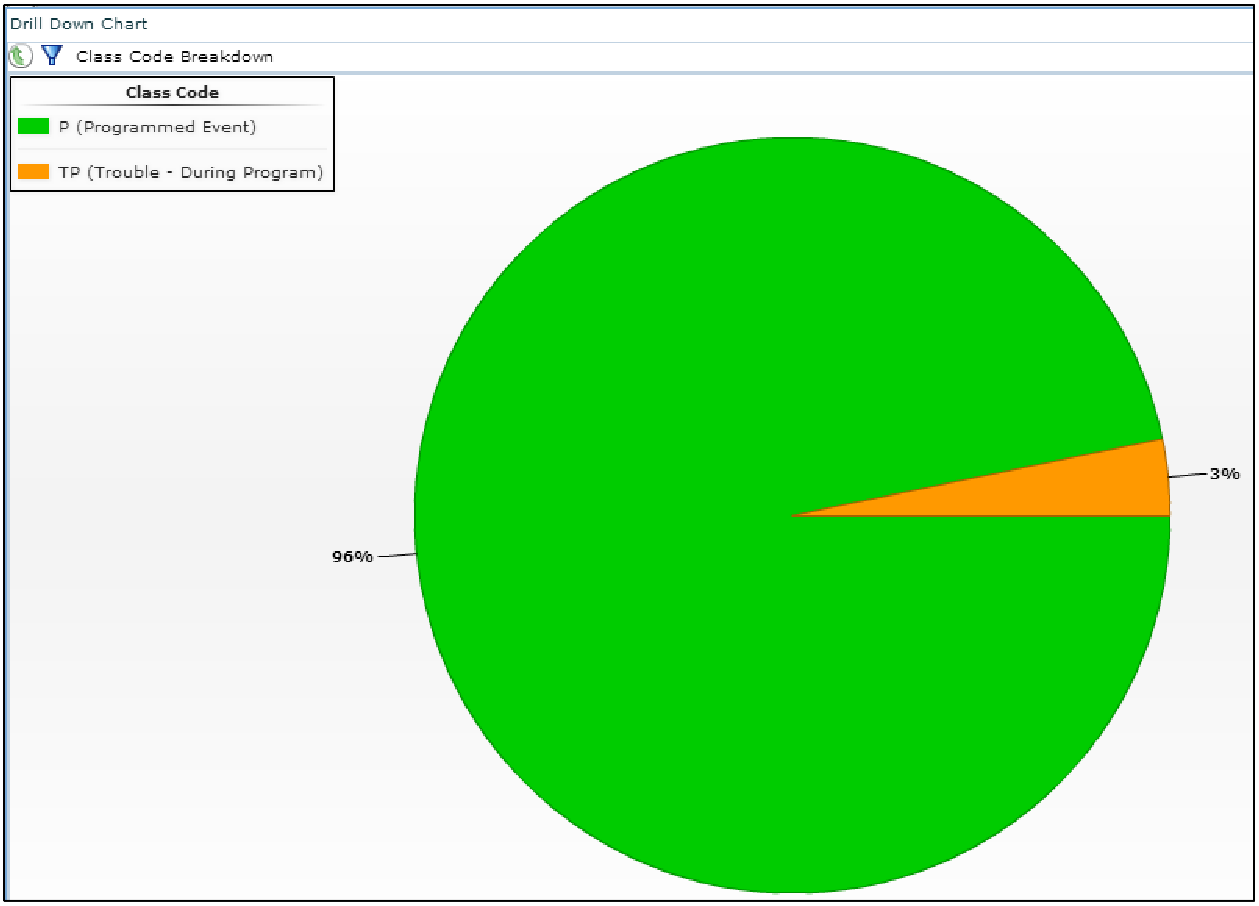

Figure 159: Oil Well #11; Percentage of Class Code Breakdowns

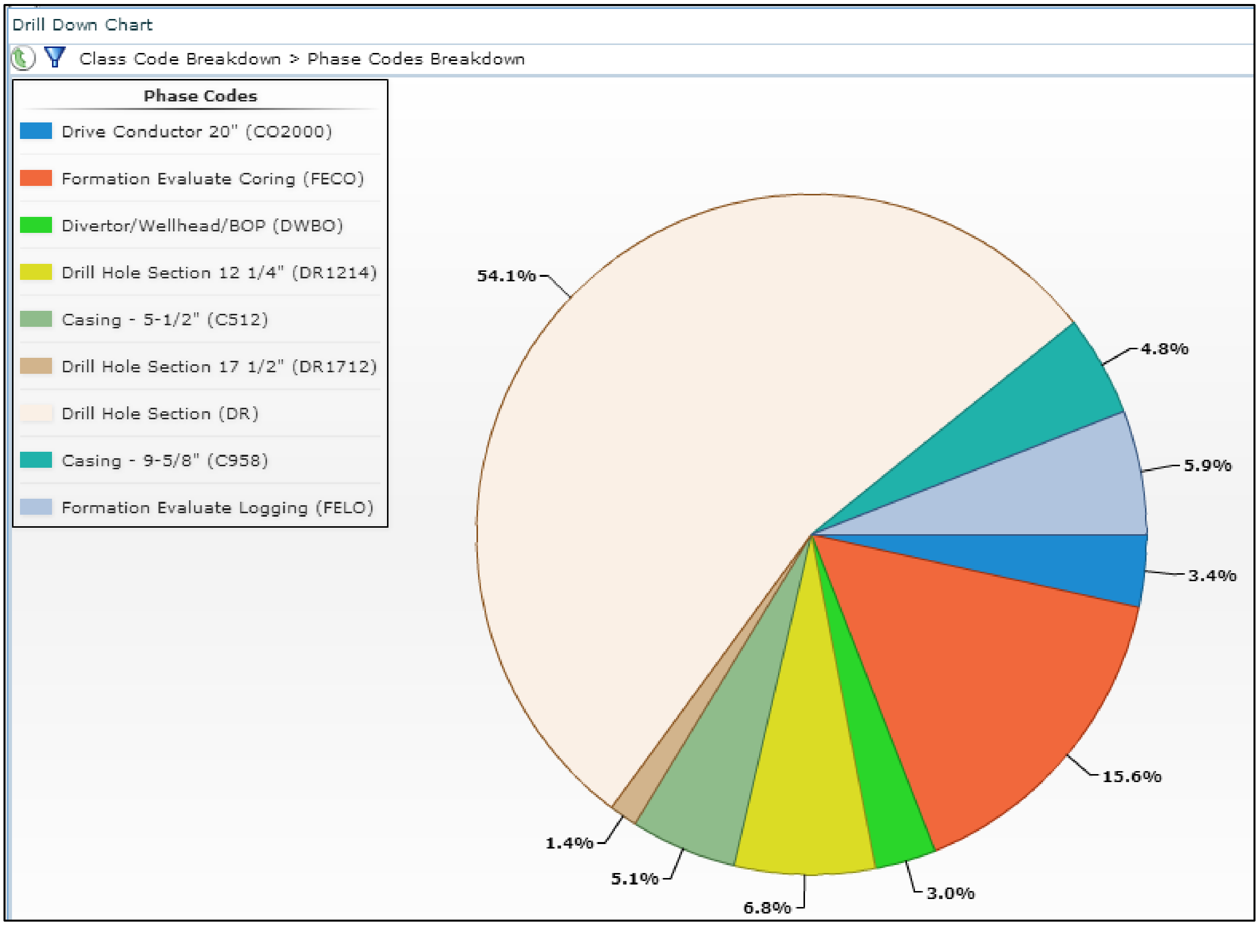

Figure 160: Oil Well #11; Percentage of Programmed Phase Code Breakdowns

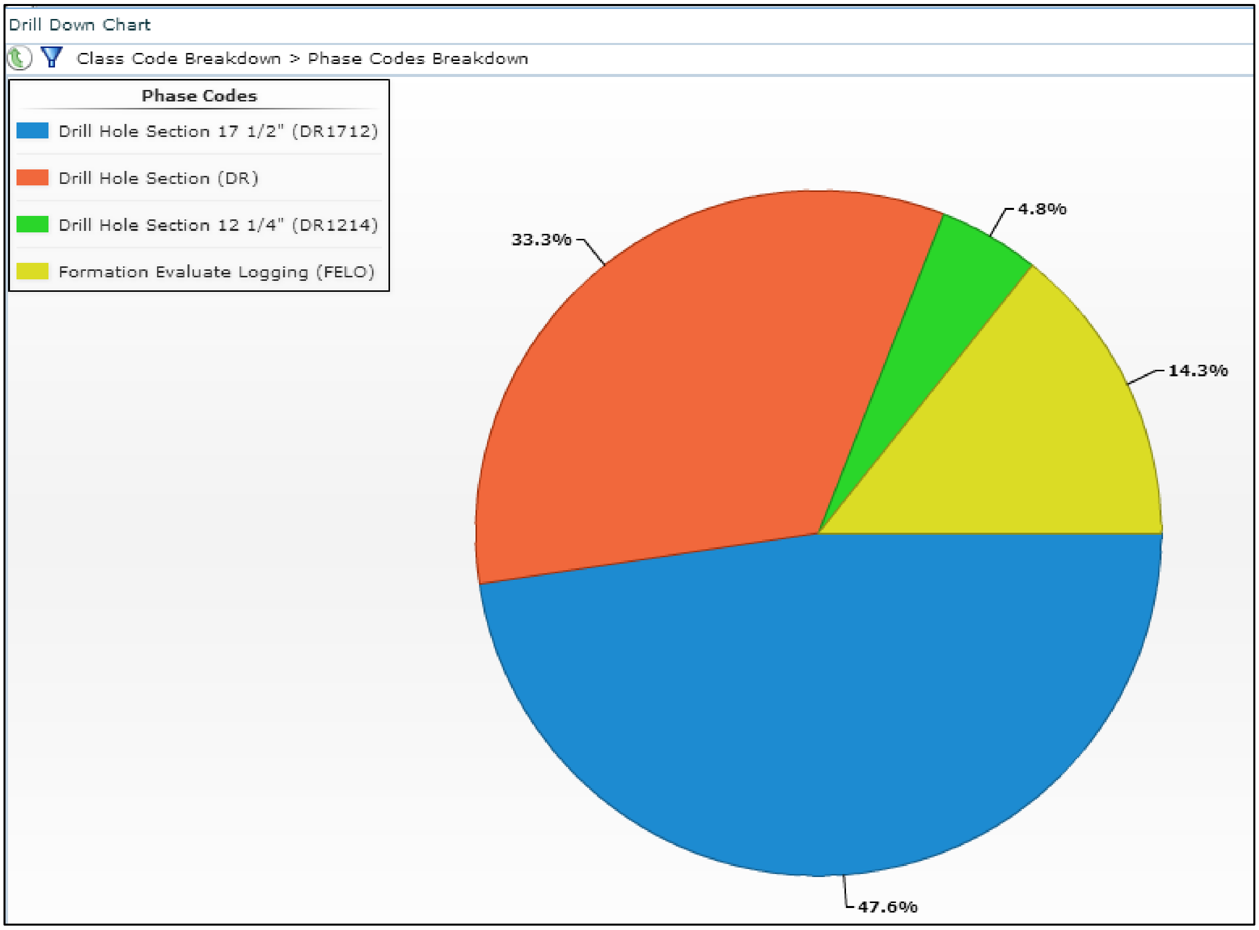

Figure 161: Oil Well #11; Percentage of Trouble during Programmed Phase Code Breakdowns

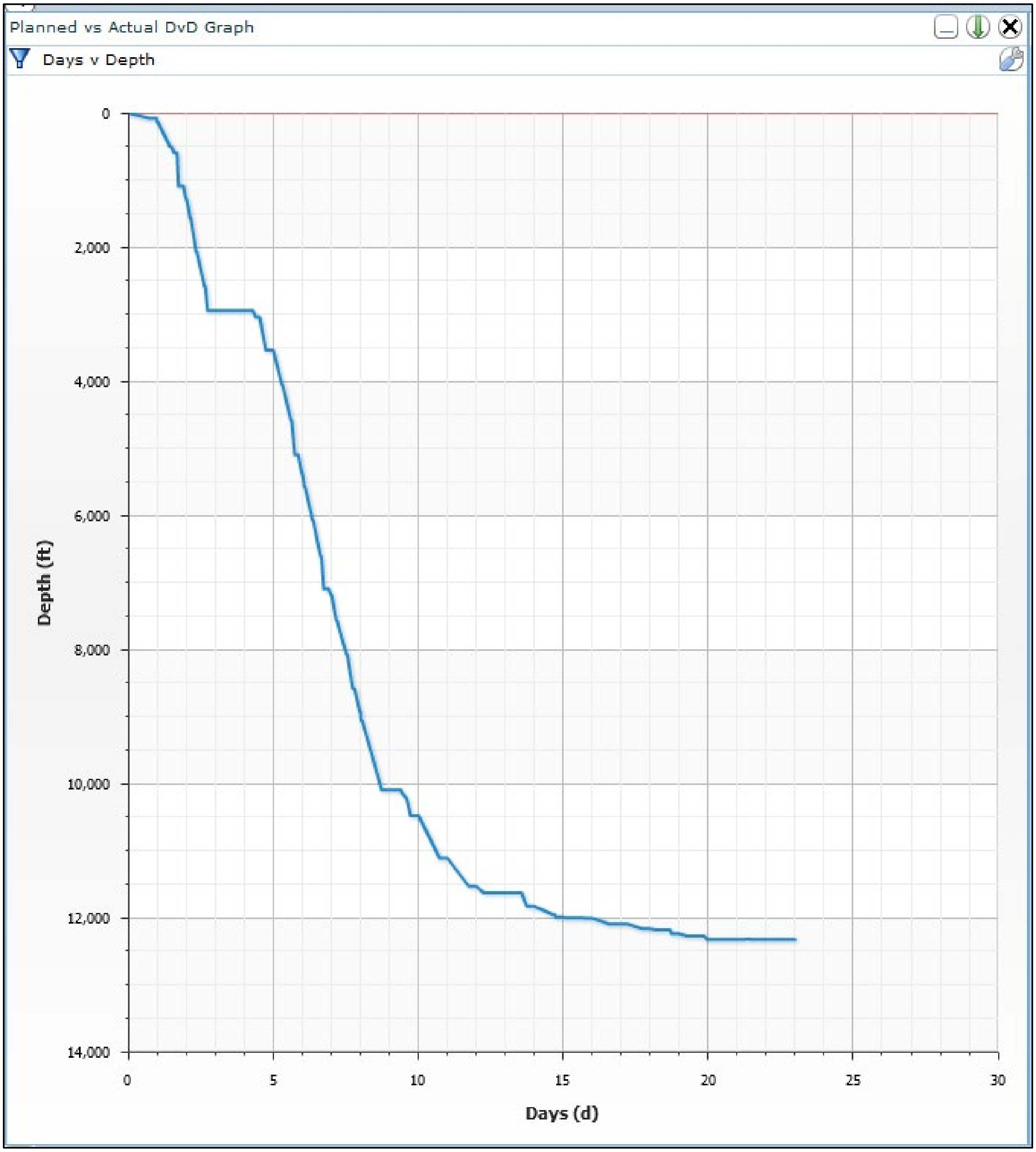

Figure 162: Oil Well #12; Days vs. Depth Drilled

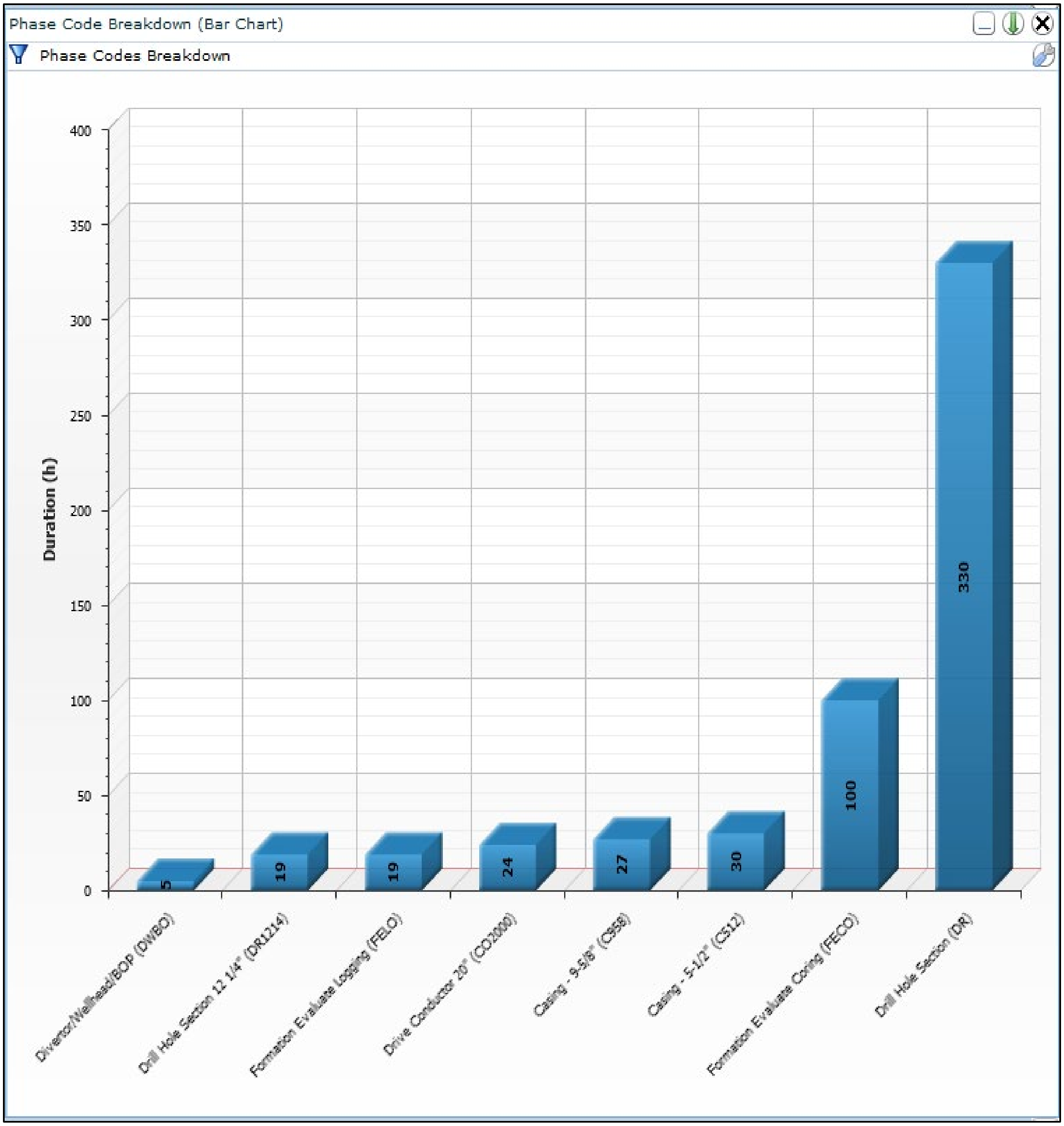

Figure 163: Oil Well #12; Phase Code Breakdown

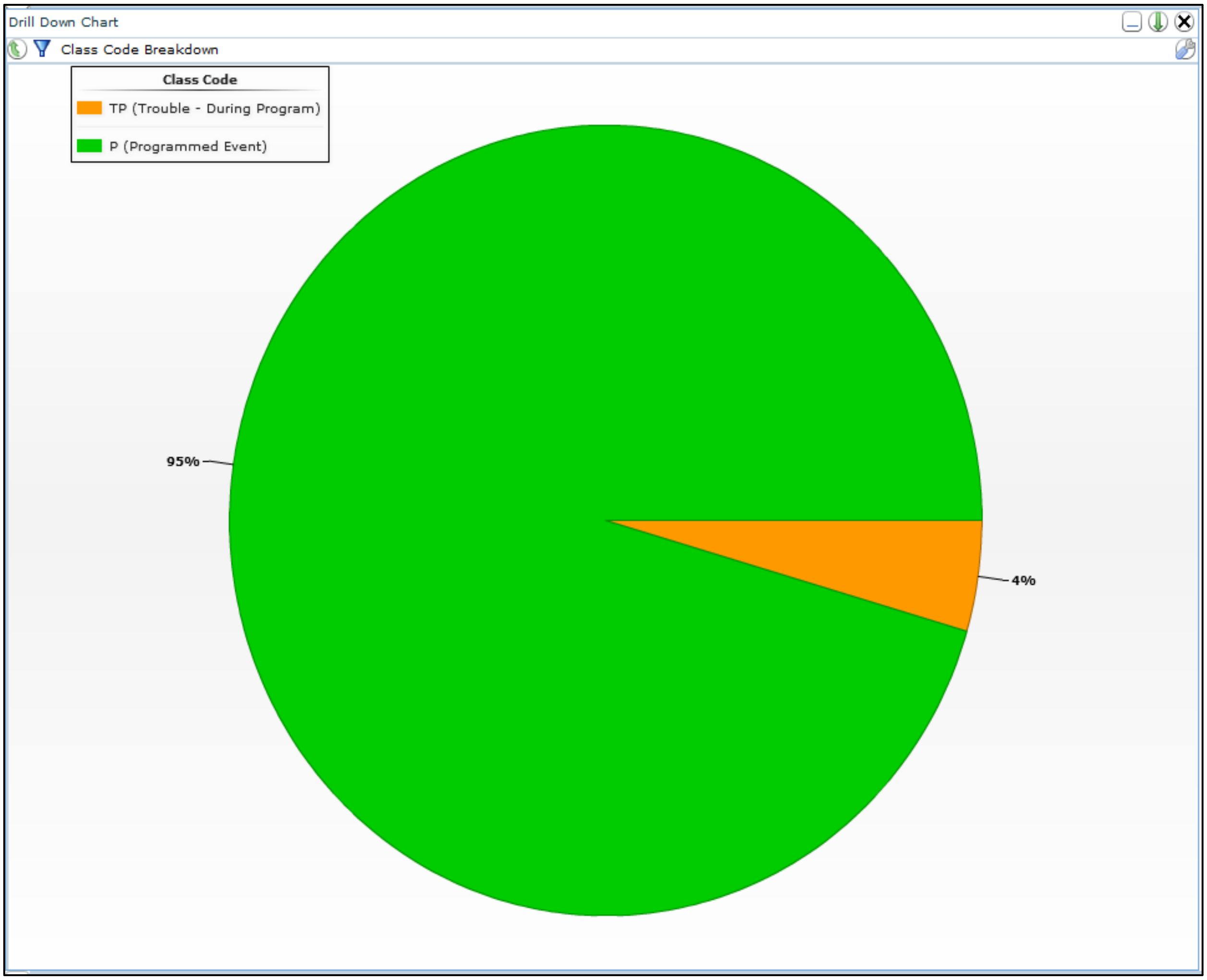

Figure 164: Oil Well #12; Percentage of Class Code Breakdown

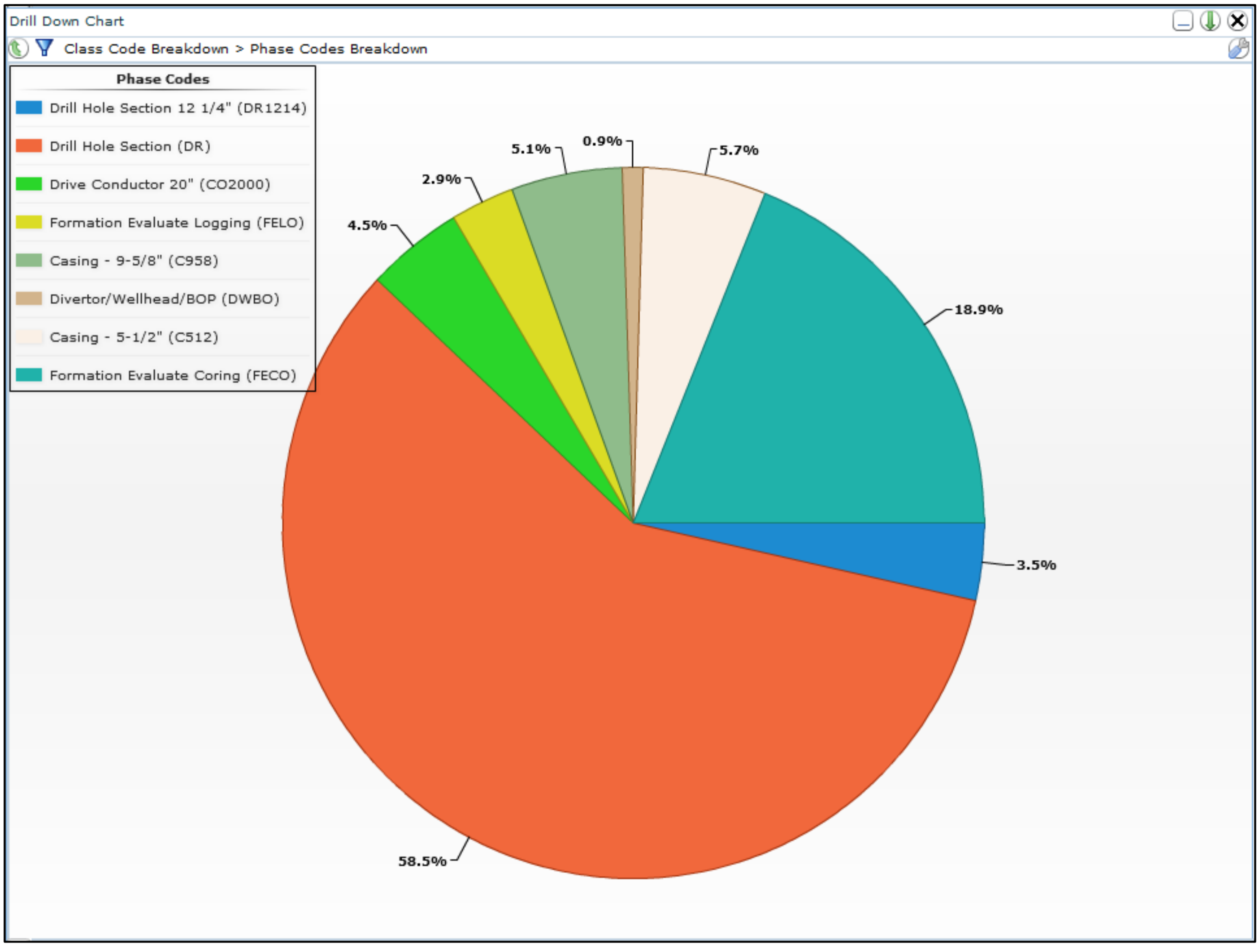

Figure 165: Oil Well #12; Percentage of Programmed Phase Code Breakdown

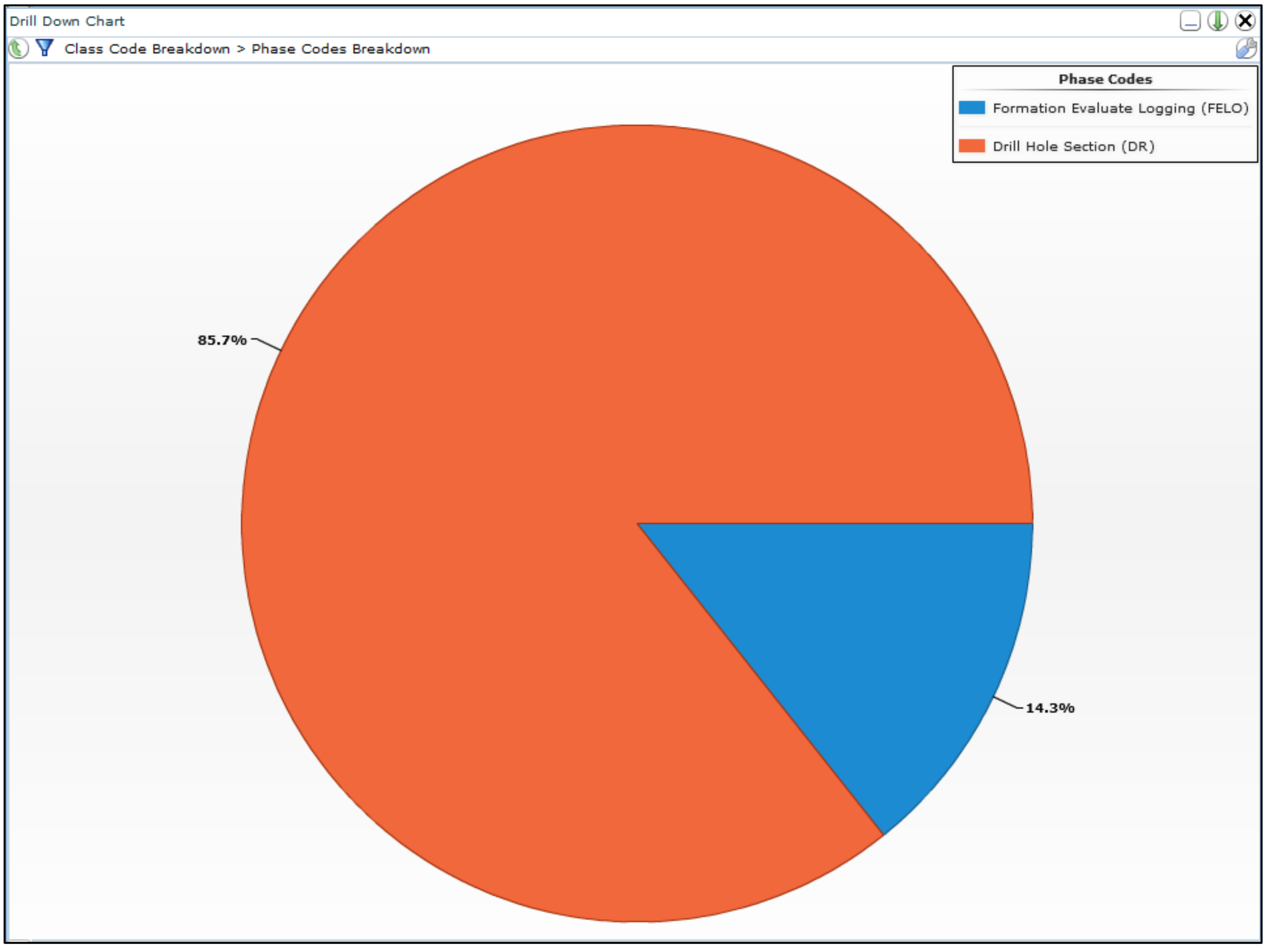

Figure 166: Oil Well #12; Percentage of Trouble During Programmed Phase Code Breakdown

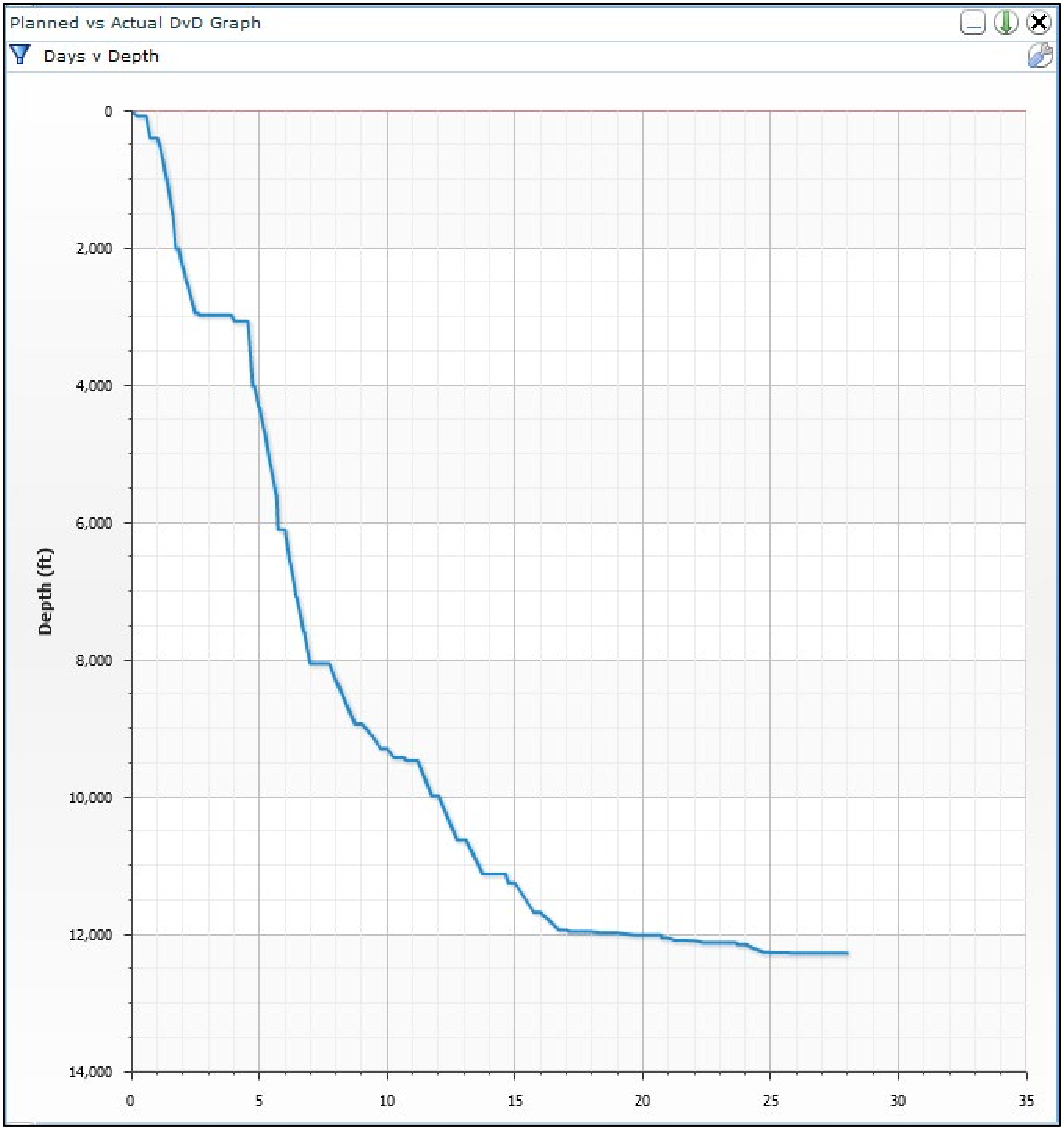

Figure 167: Oil Well #13; Days vs. Depth Drilled

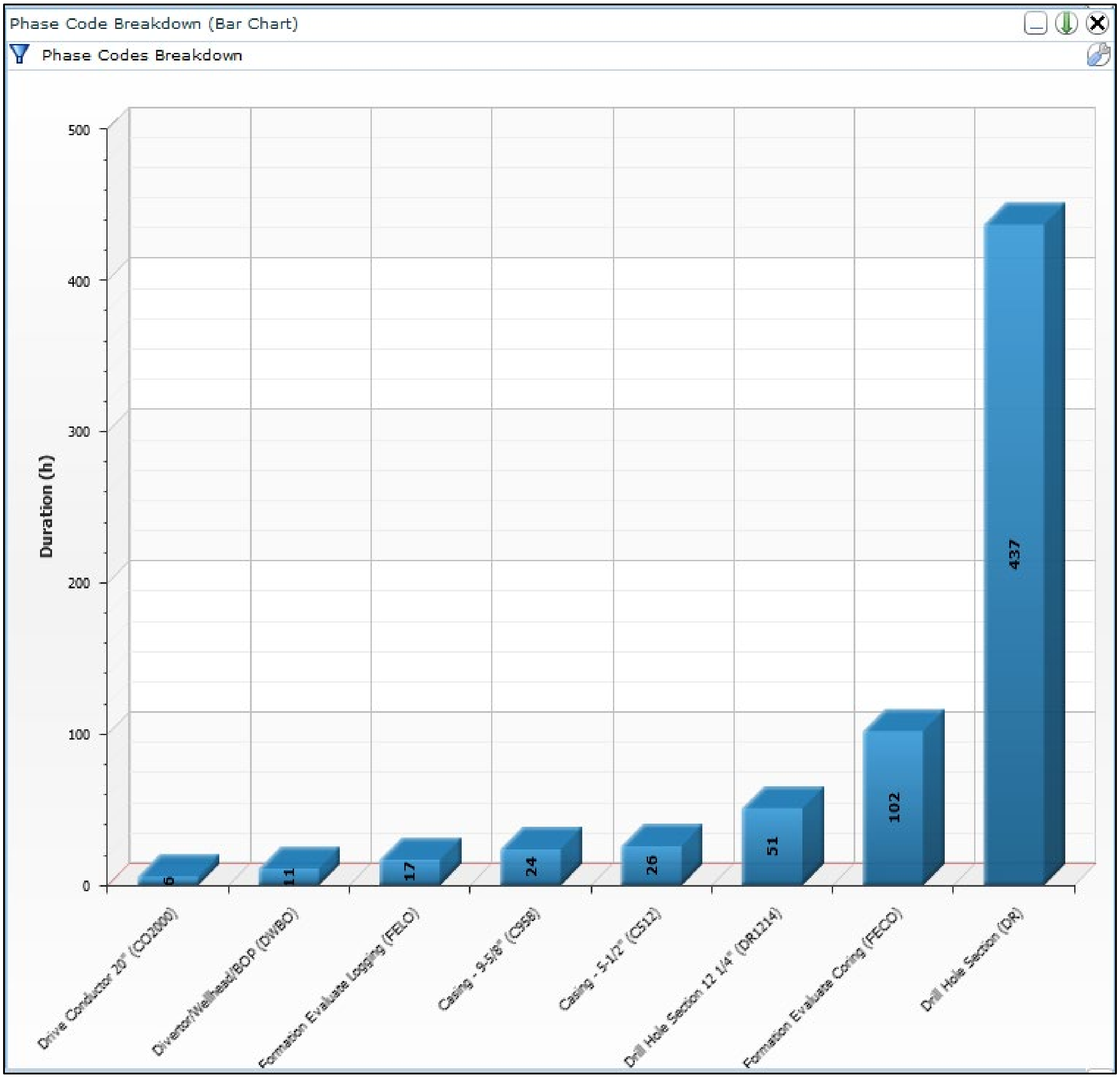

Figure 168: Oil Well #13; Phase Code Breakdown

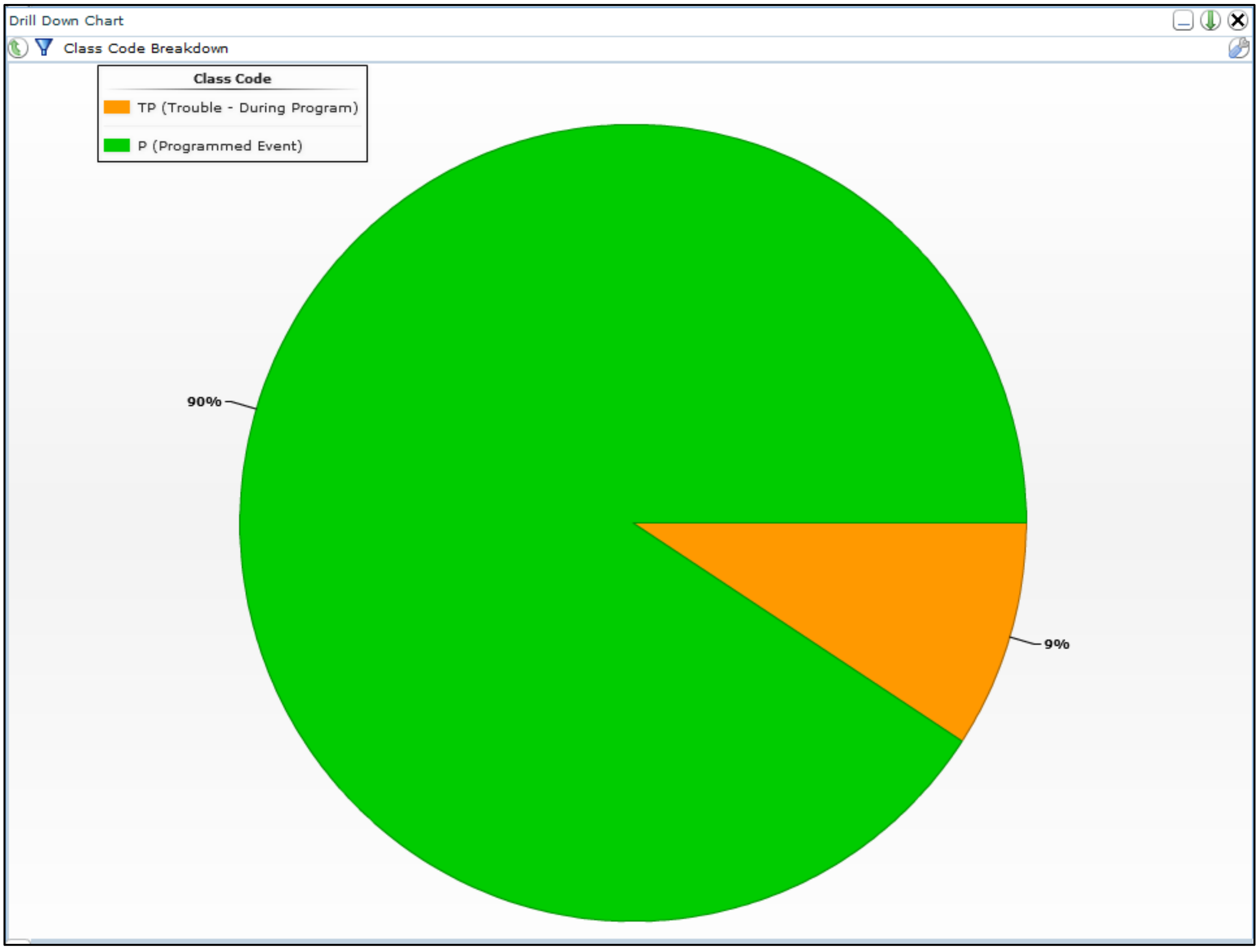

Figure 169: Oil Well #13; Percentage of Class Code Breakdown

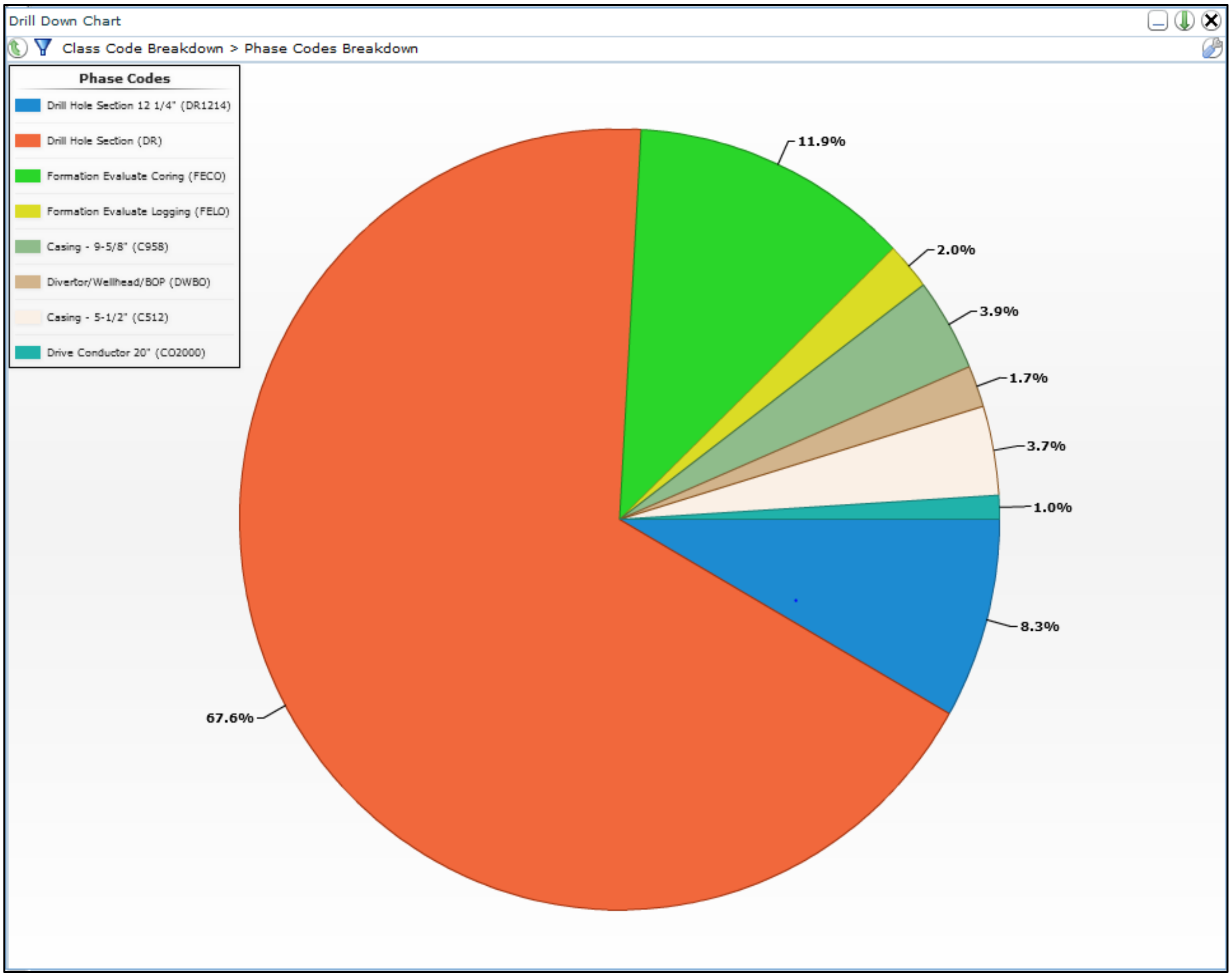

Figure 170: Oil Well #13; Percentage of Programmed Phase Code Breakdown

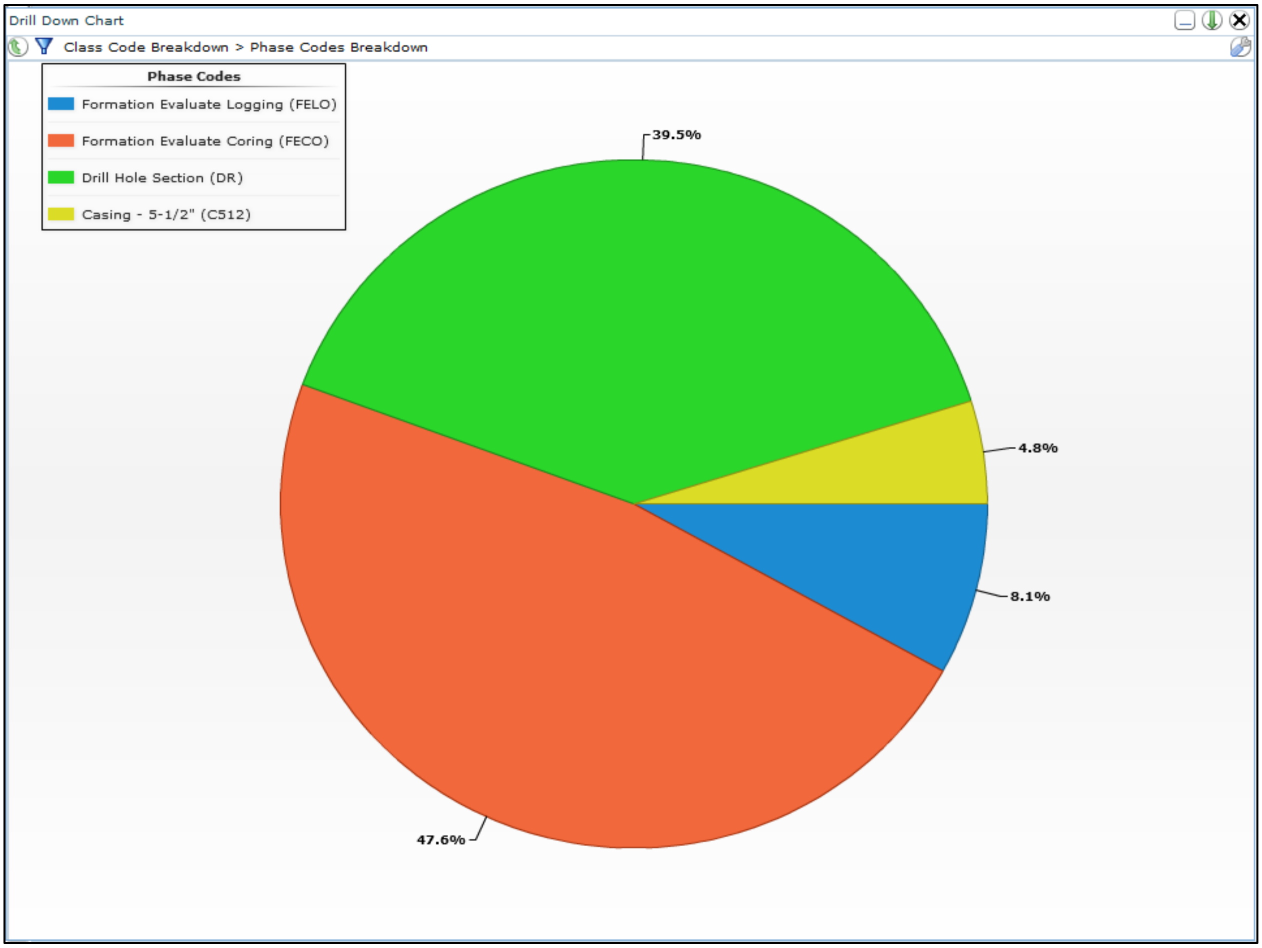

Figure 171: Oil Well #13; Percentage of Trouble During Programmed Phase Code Breakdown

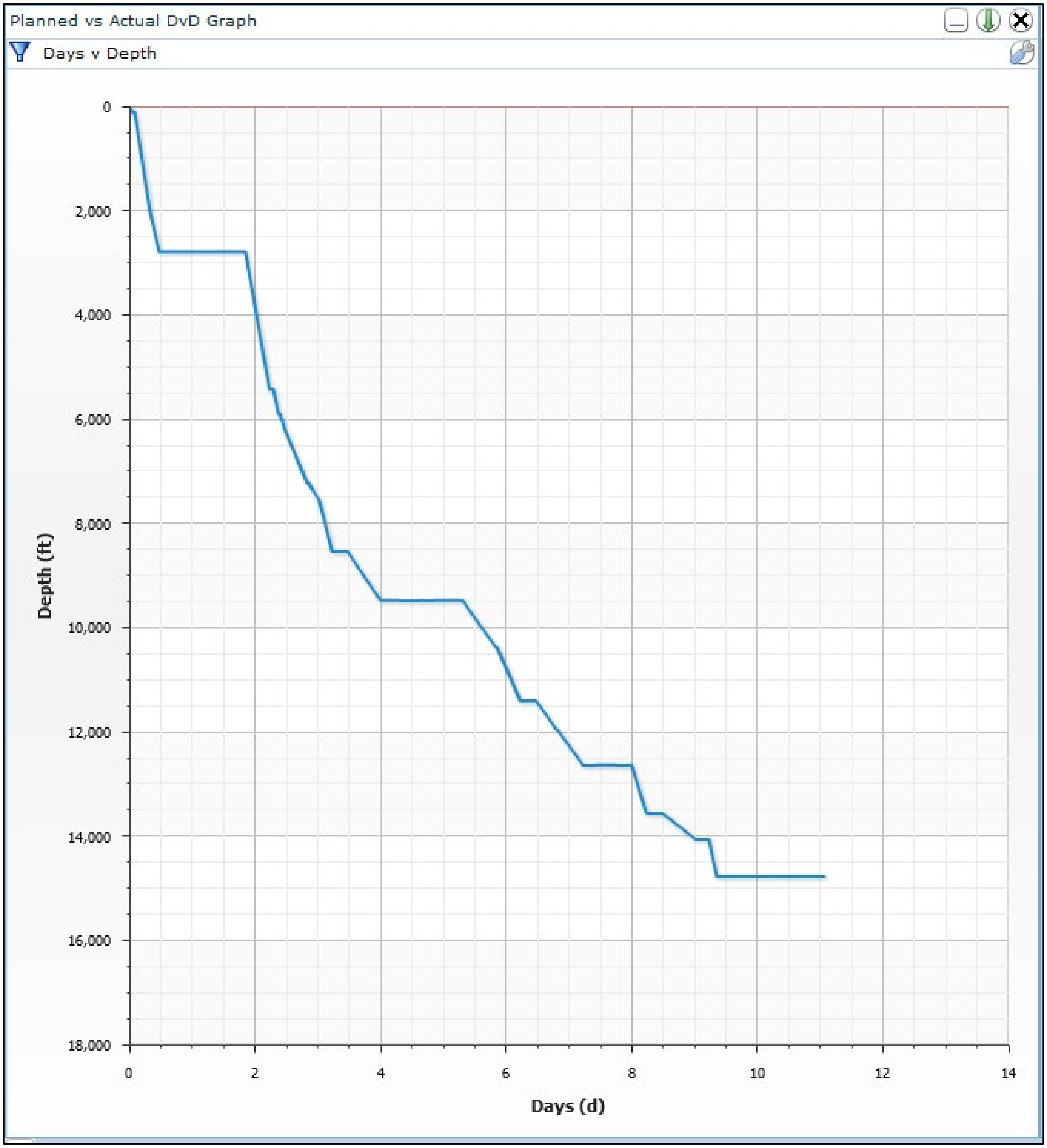

Figure 172: Oil Well #14; Days vs. Depth Drilled

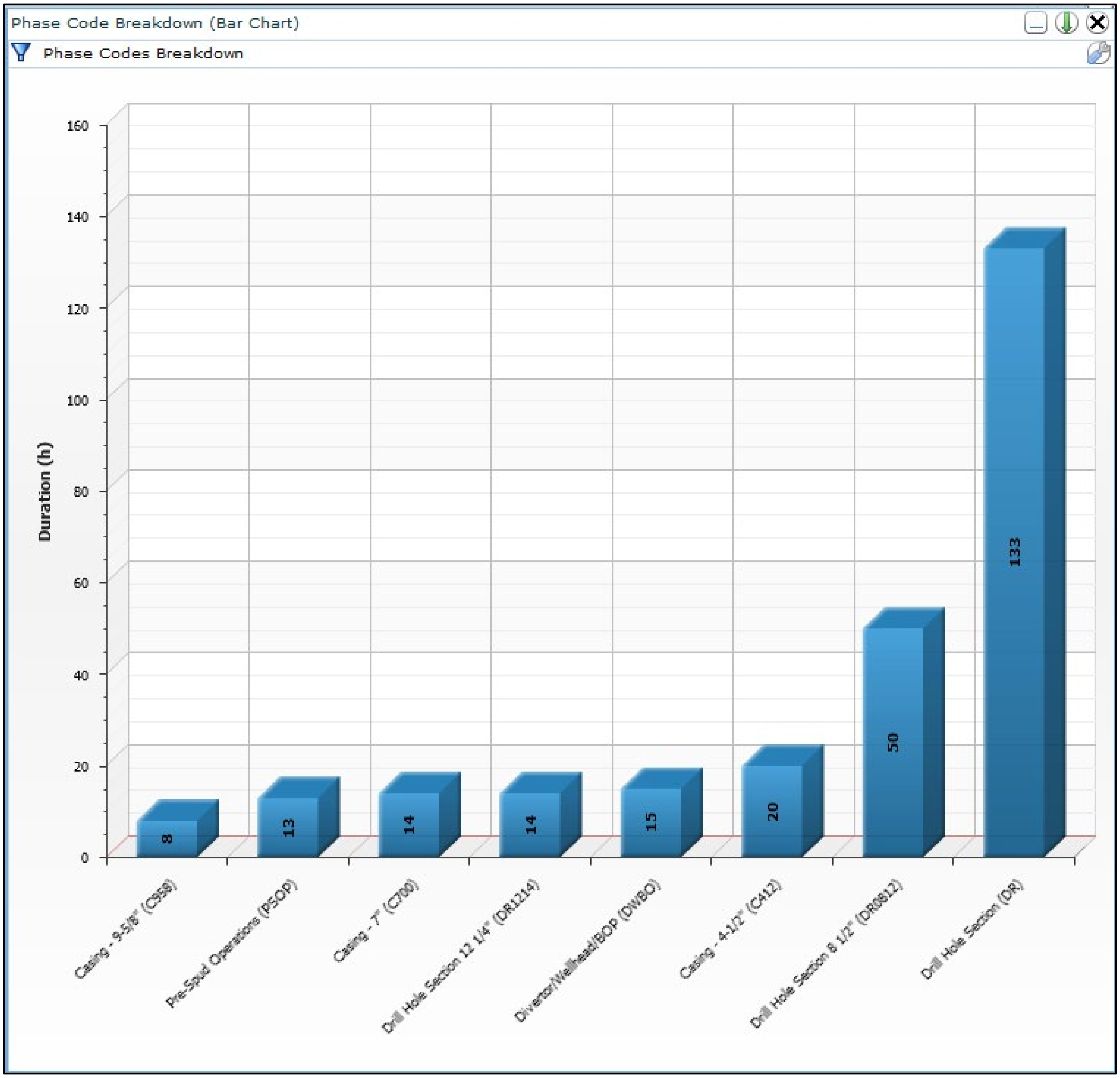

Figure 173: Oil Well #14; Phase Code Breakdown

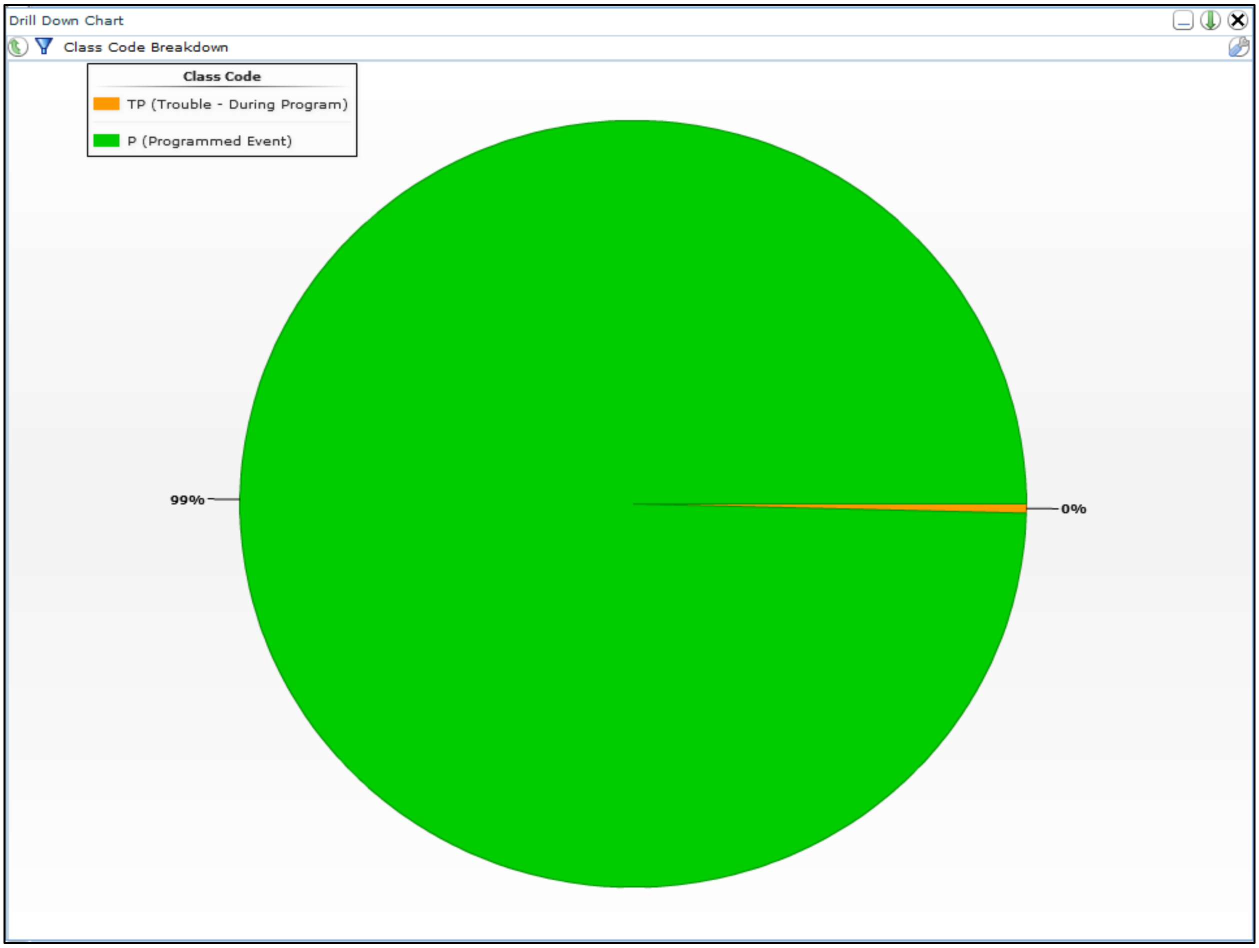

Figure 174: Oil Well #14; Percentage of Class Code Breakdown

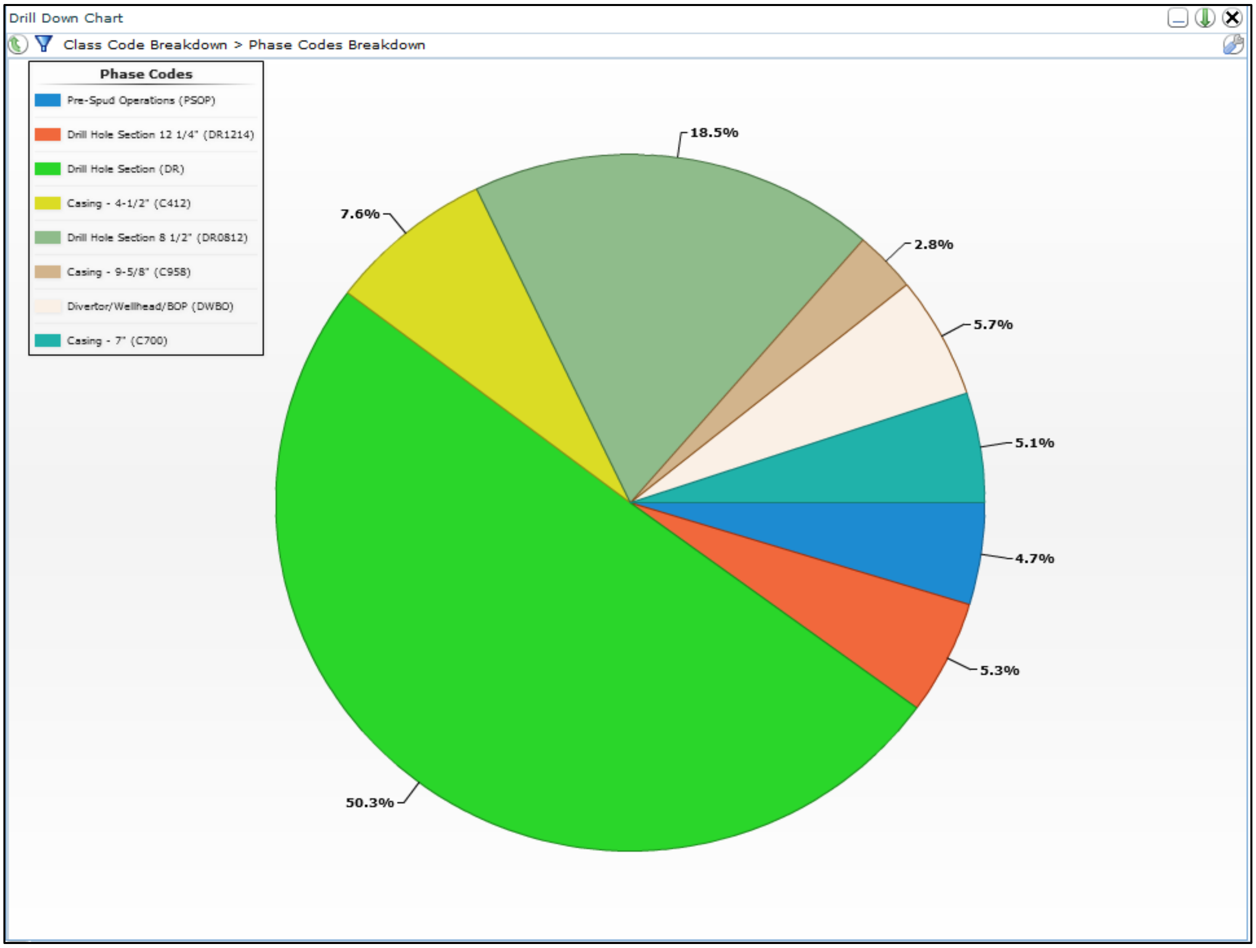

Figure 175: Oil Well #14; Percentage of Programmed Phase Code Breakdown

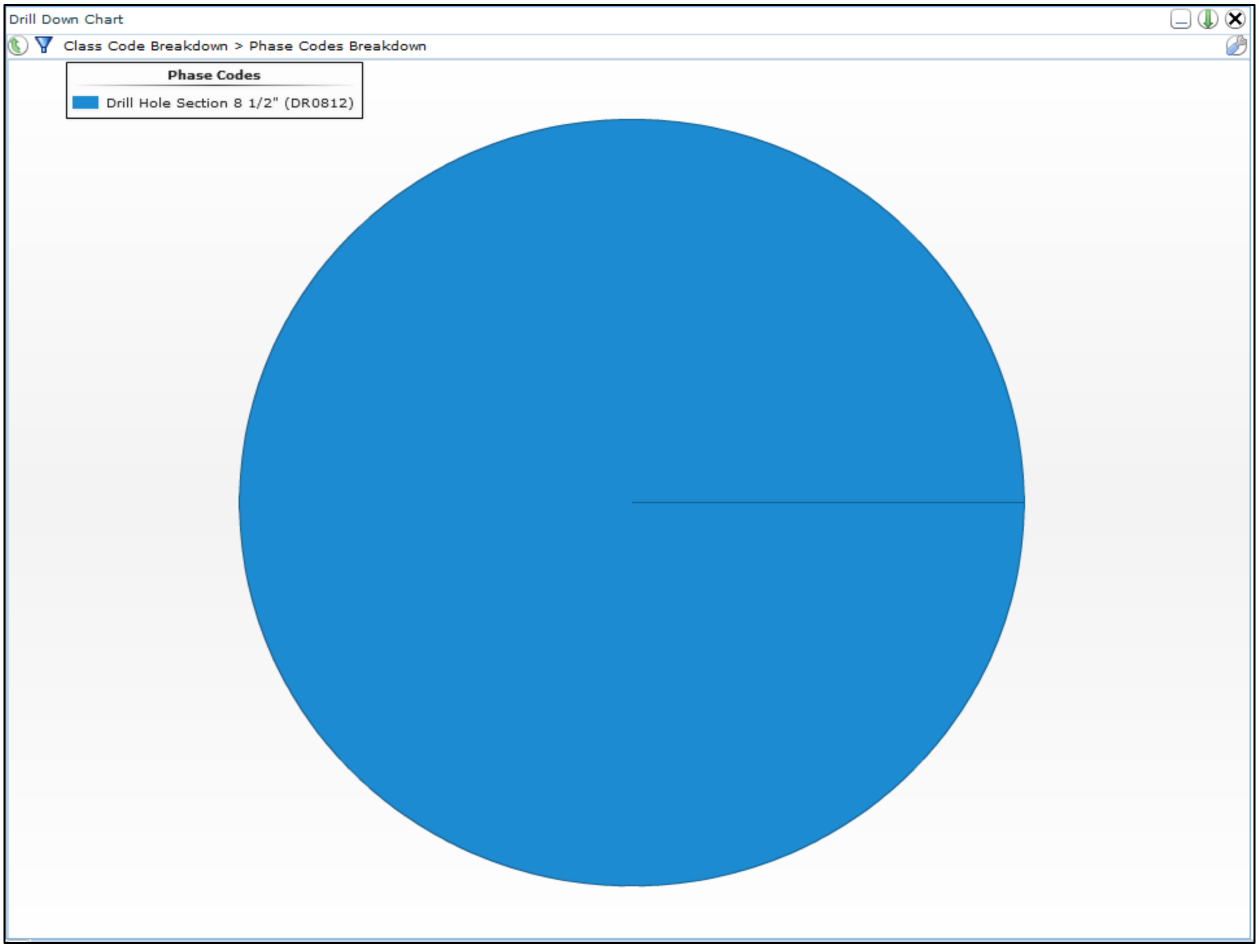

Figure 176: Oil Well #14; Percentage of Trouble During Programmed Phase Code Breakdown

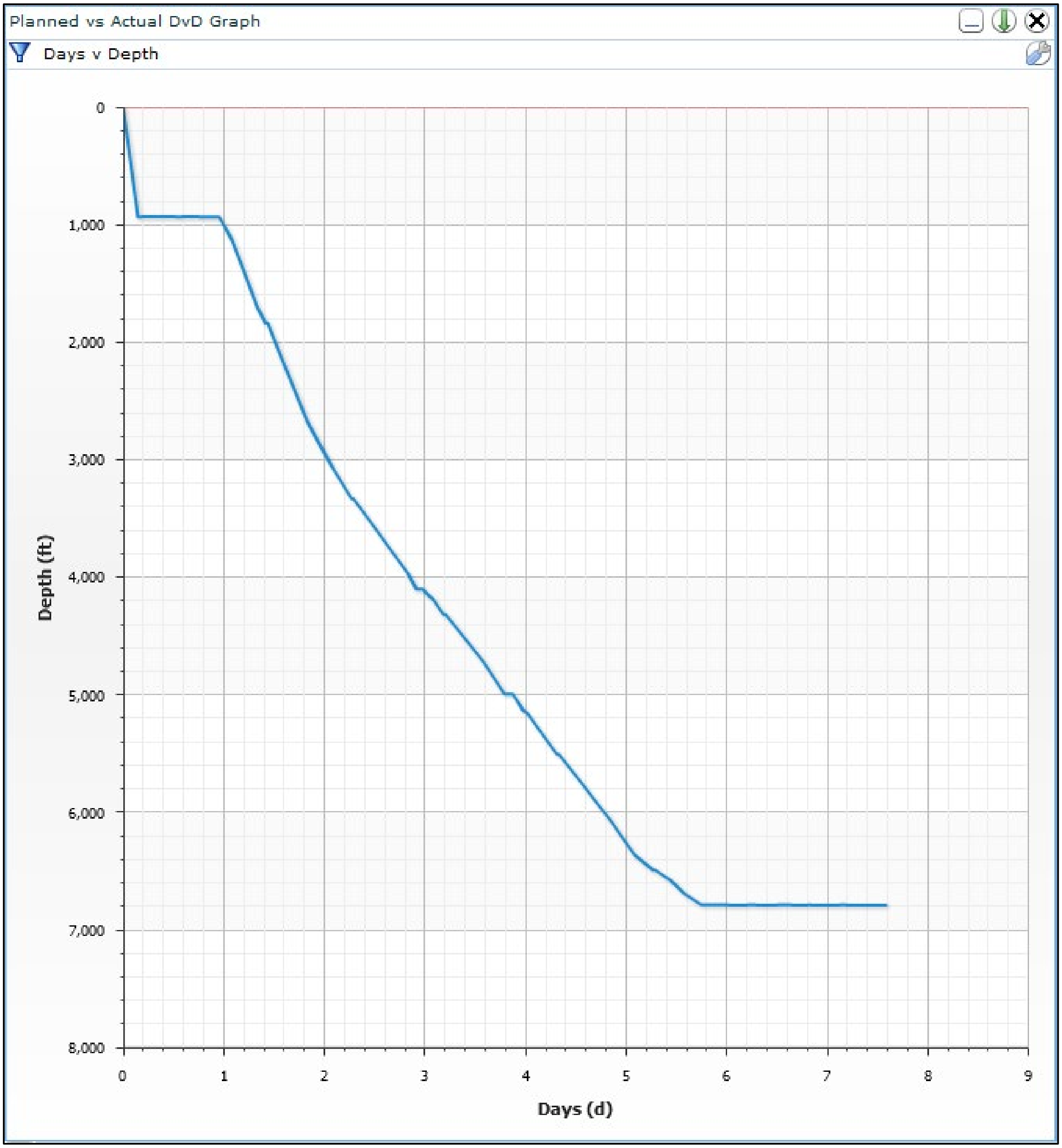

Figure 177: Oil Well #15; Days vs. Depth Drilled

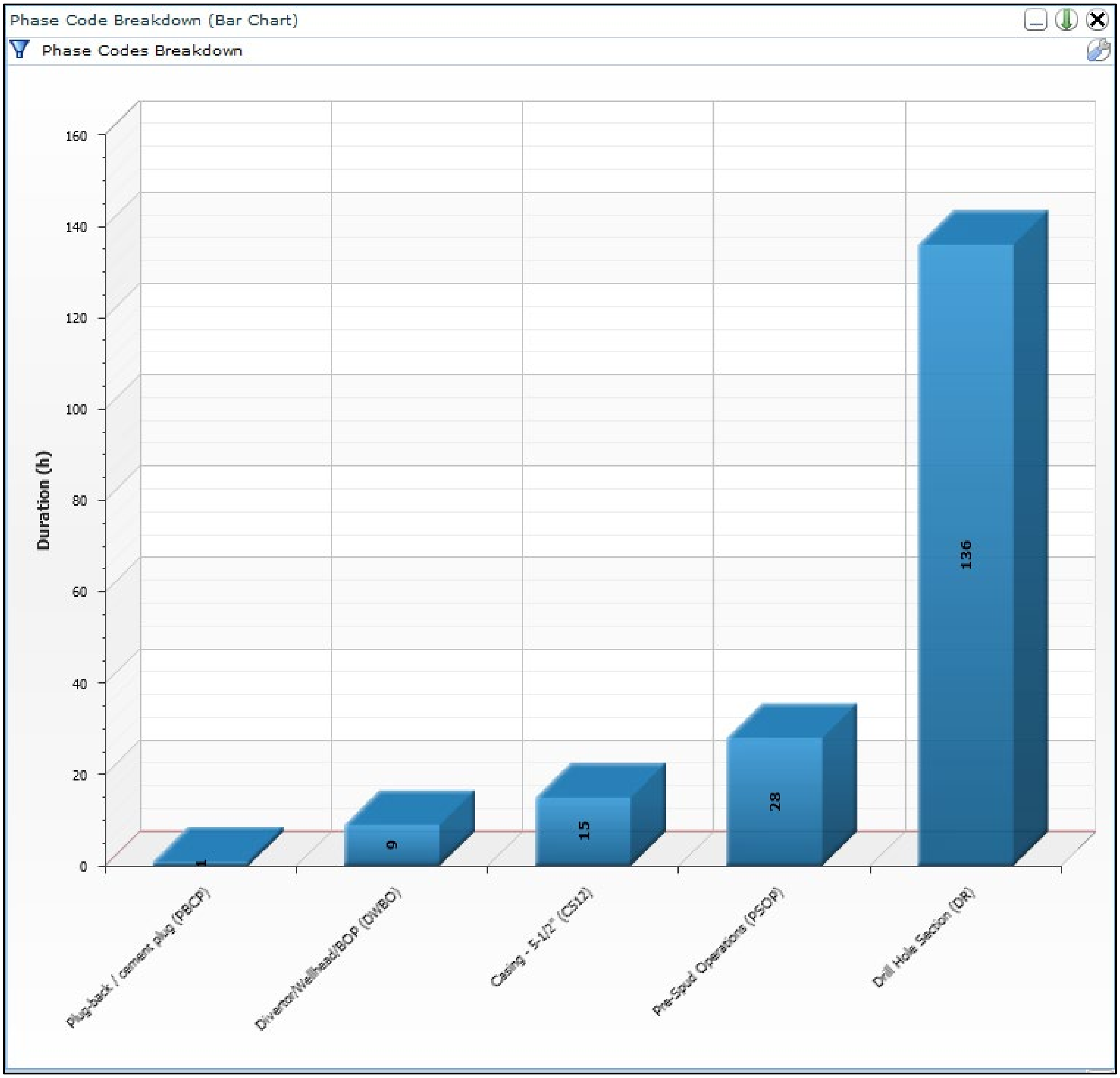

Figure 178: Oil Well #15; Phase Code Breakdown

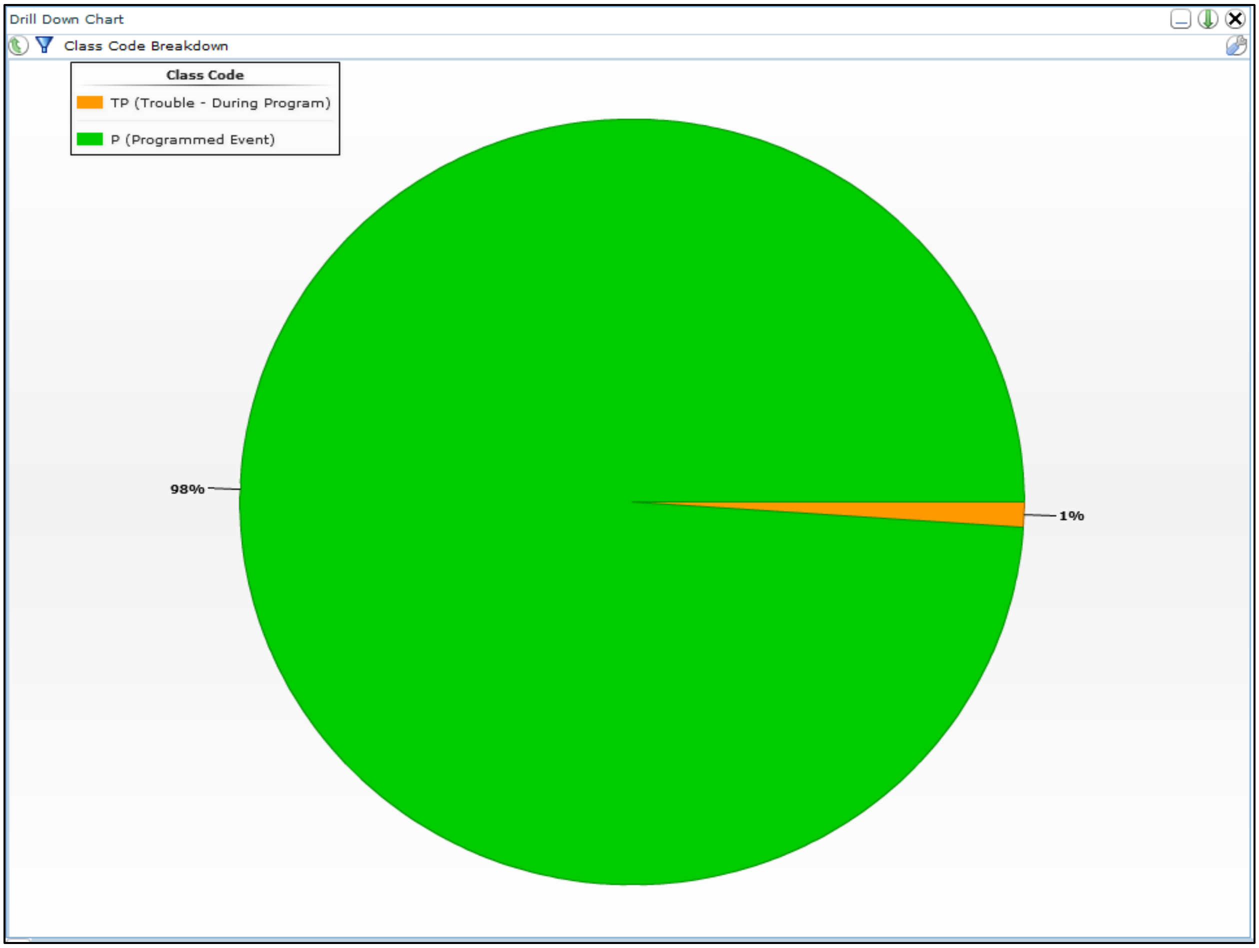

Figure 179: Oil Well #15; Percentage of Class Code Breakdown

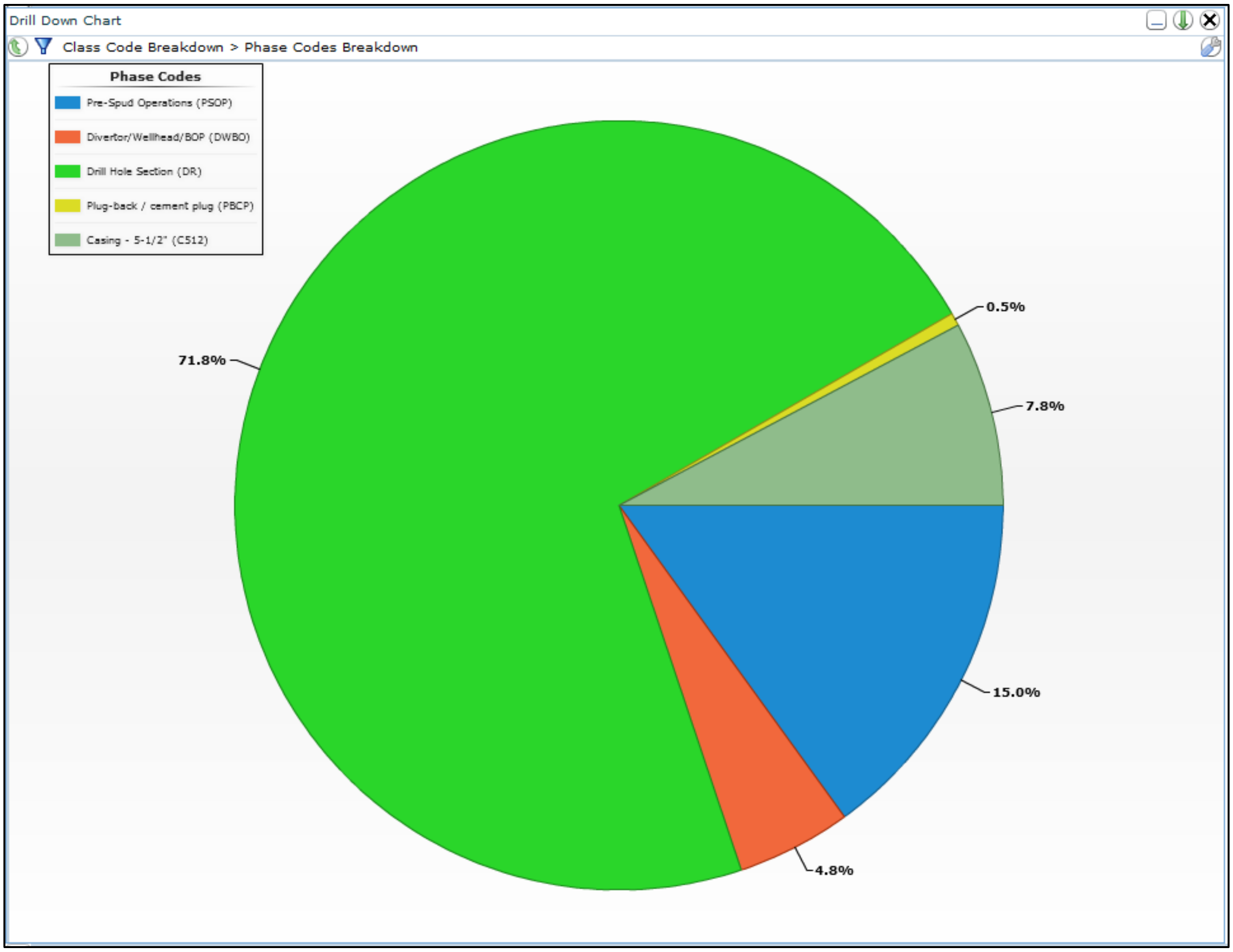

Figure 180: Oil Well #15; Percentage of Programmed Phase Code Breakdown

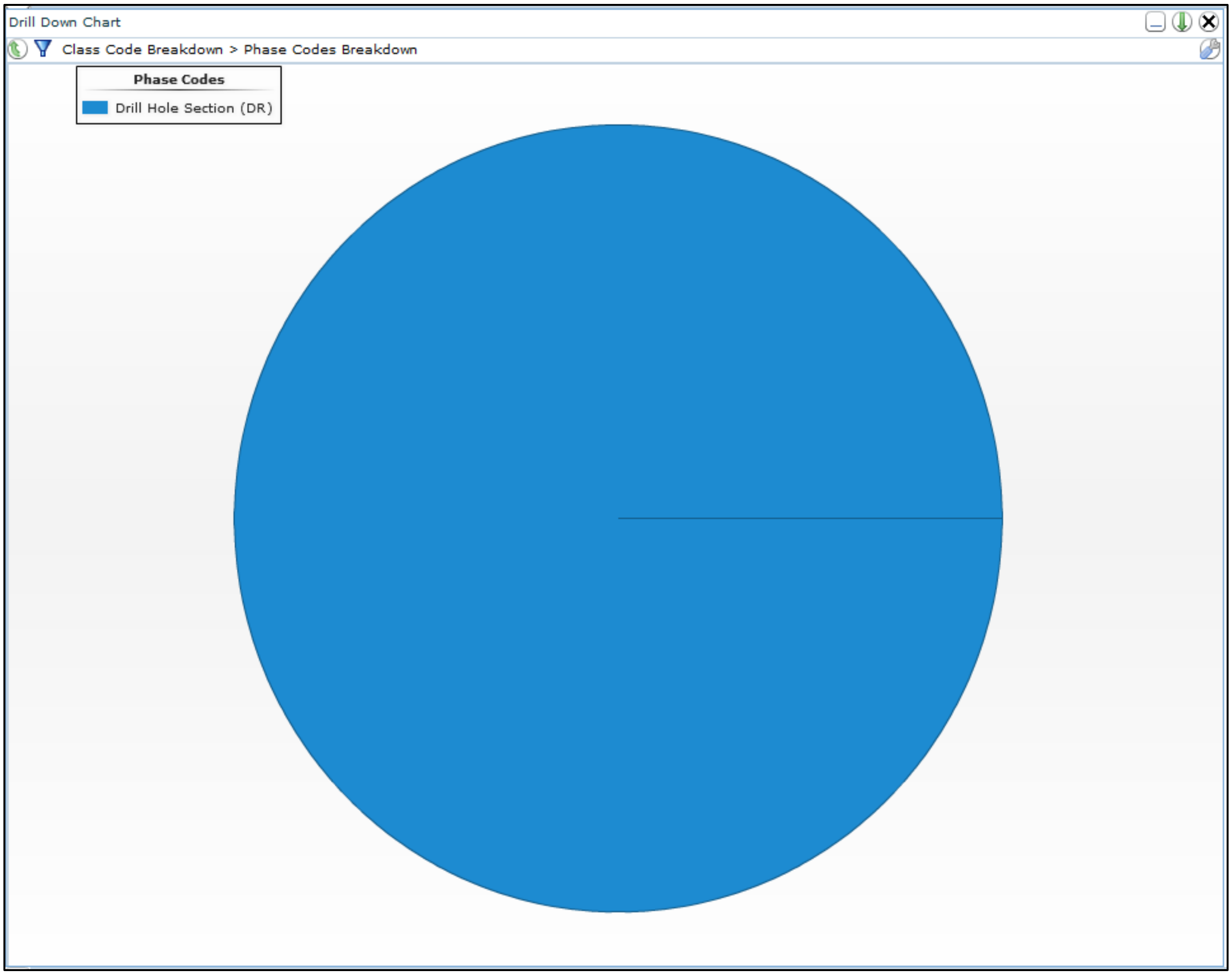

Figure 181: Oil Well #15; Percentage of Trouble During Programmed Phase Code Breakdown

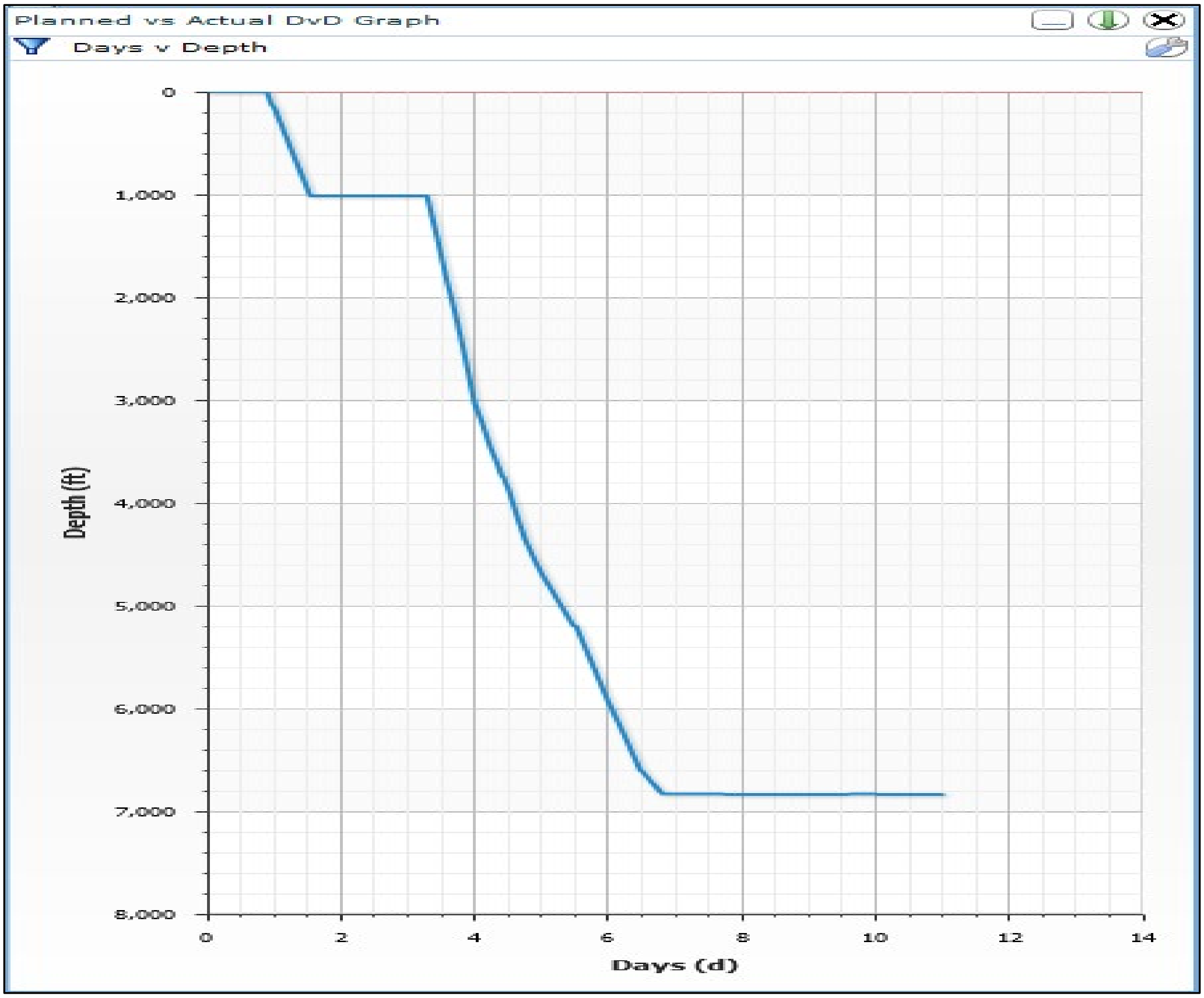

Figure 182: Oil Well #16; Days vs. Depth Drilled

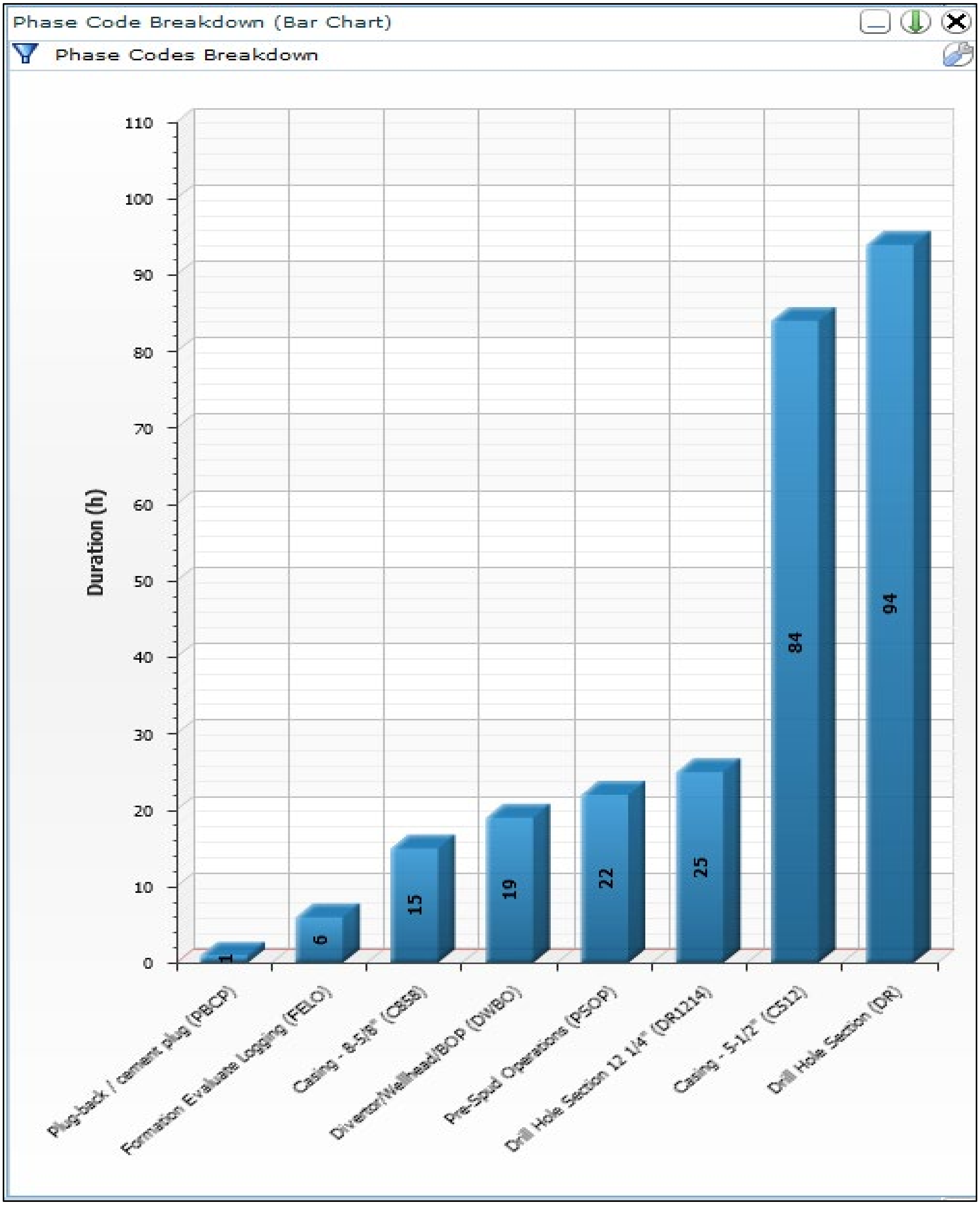

Figure 183: Oil Well #16; Phase Code Breakdown

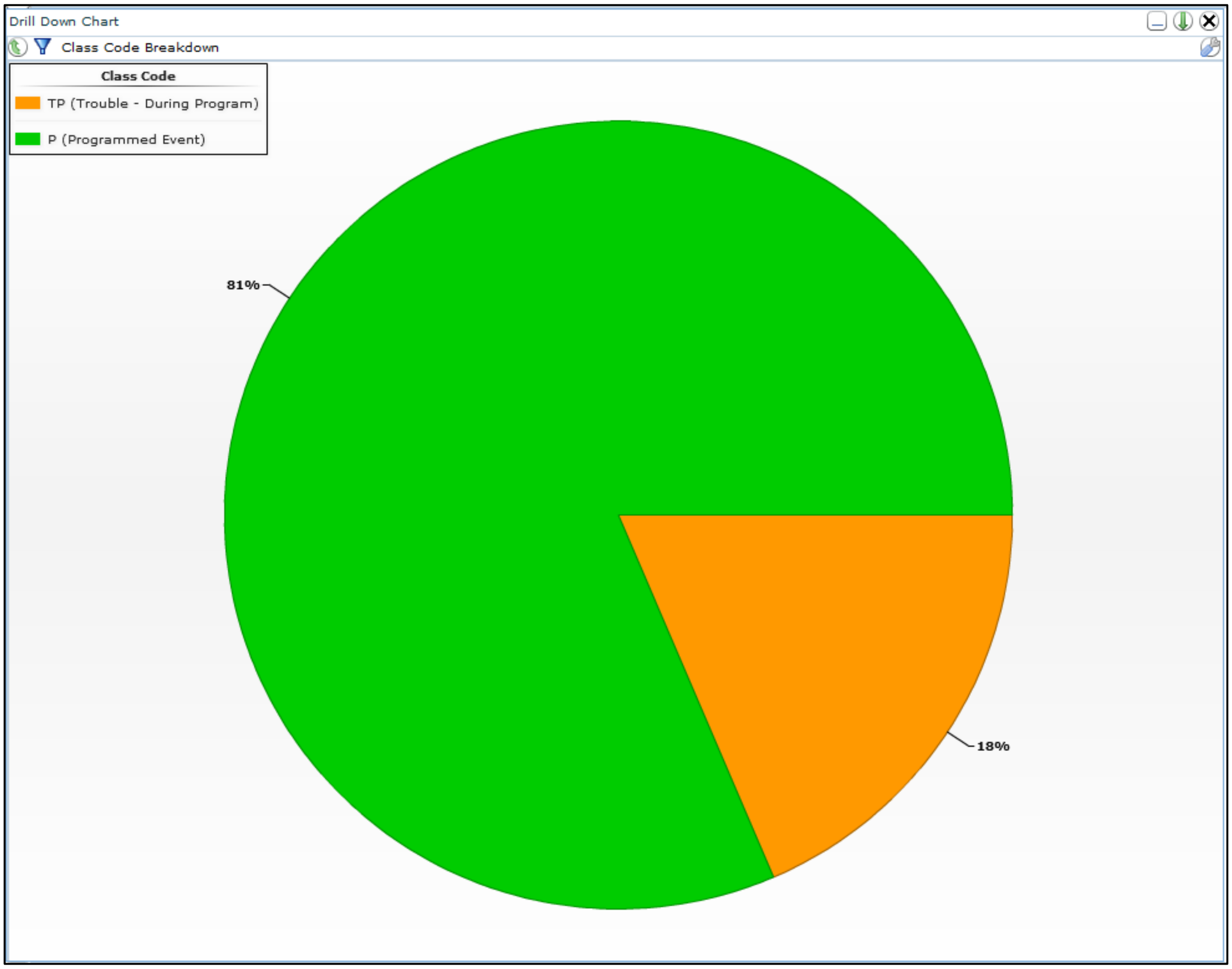

Figure 184: Oil Well #16; Percentage of Class Code Breakdown

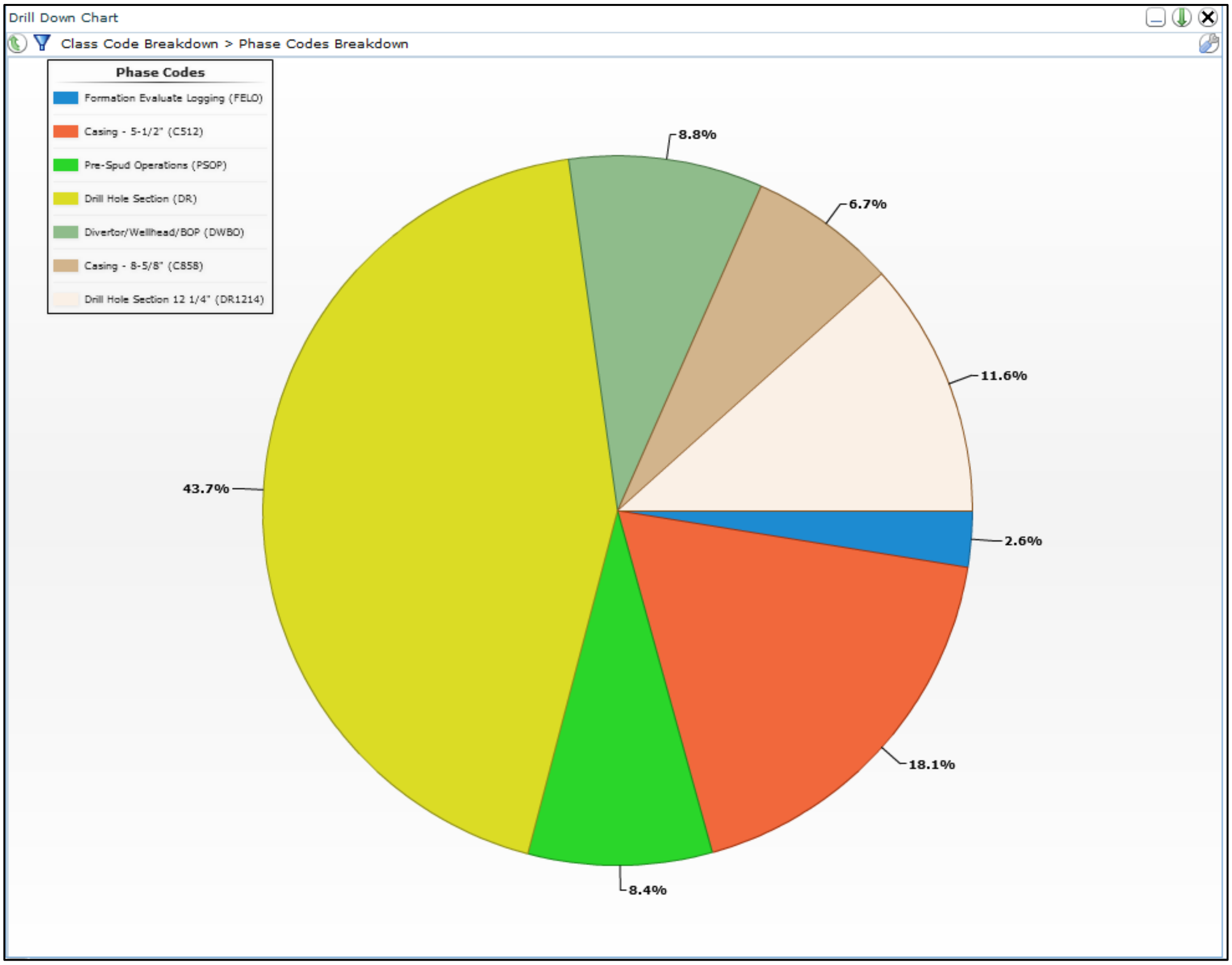

Figure 185: Oil Well #16; Percentage of Programmed Phase Code Breakdown

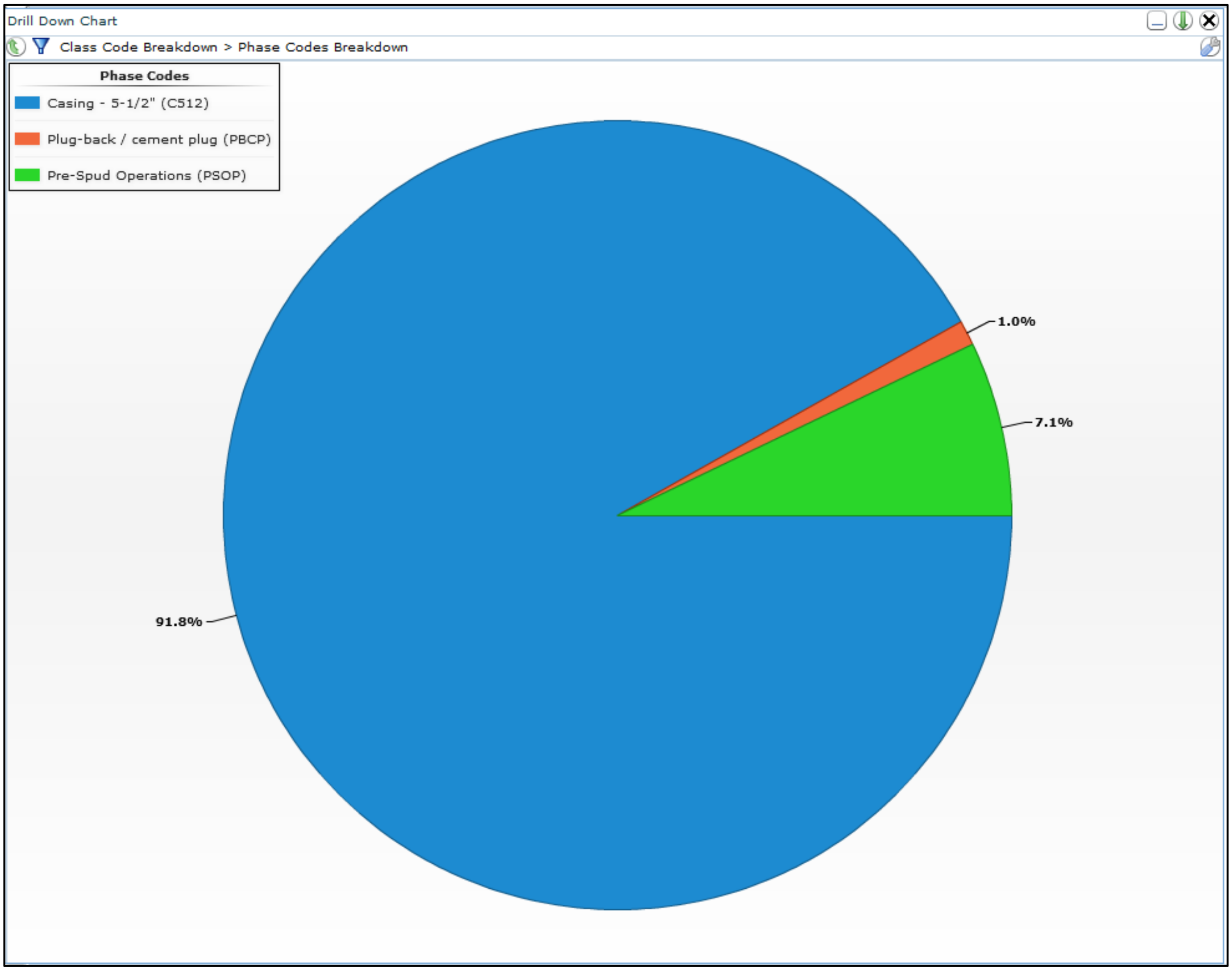

Figure 186: Oil Well #16; Percentage of Trouble During Programmed Phase Code Breakdown

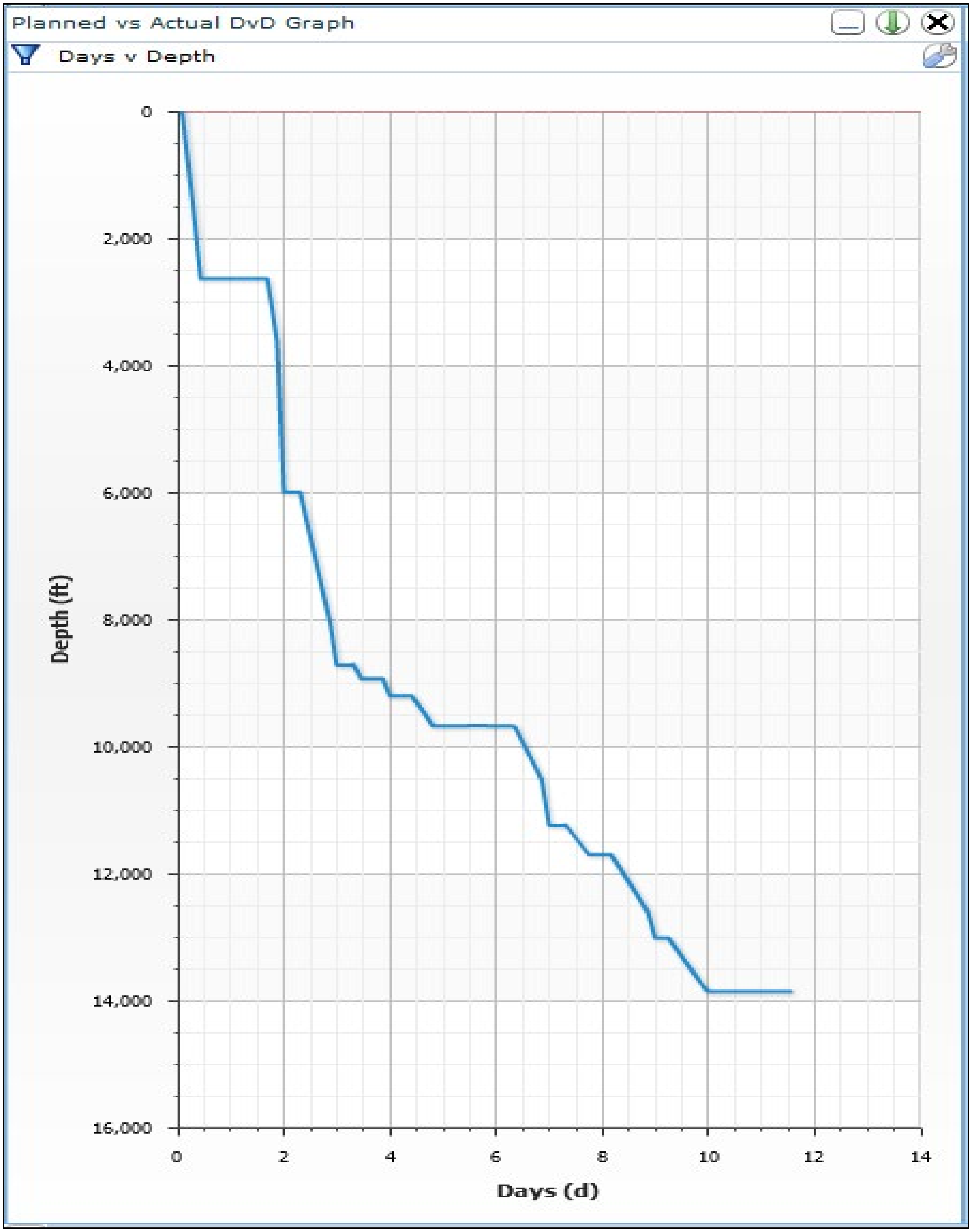

Figure 187: Oil Well #17; Days vs. Depth Drilled

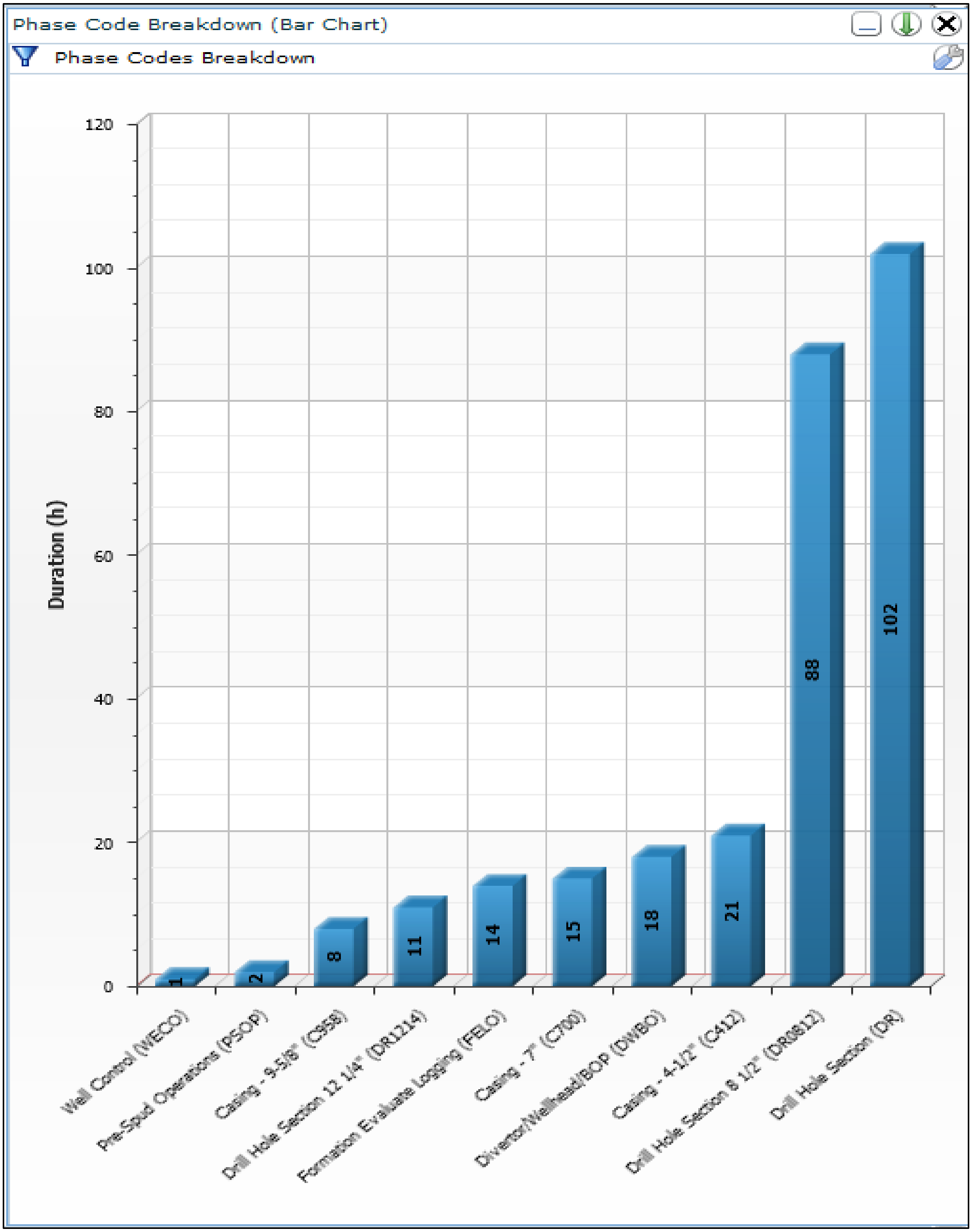

Figure 188: Oil Well #17; Phase Code Breakdown

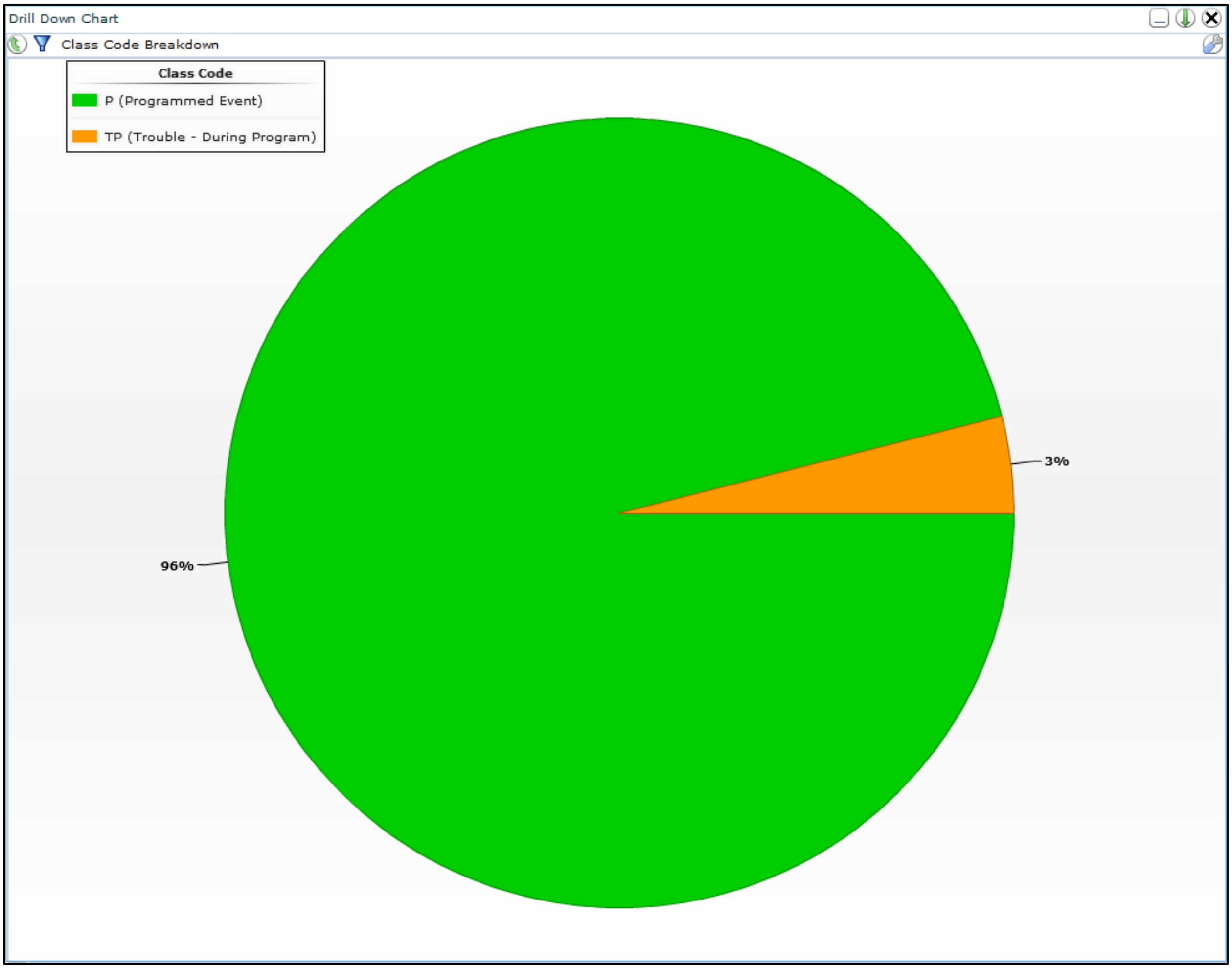

Figure 189: Oil Well #17; Percentage of Class Code Breakdown

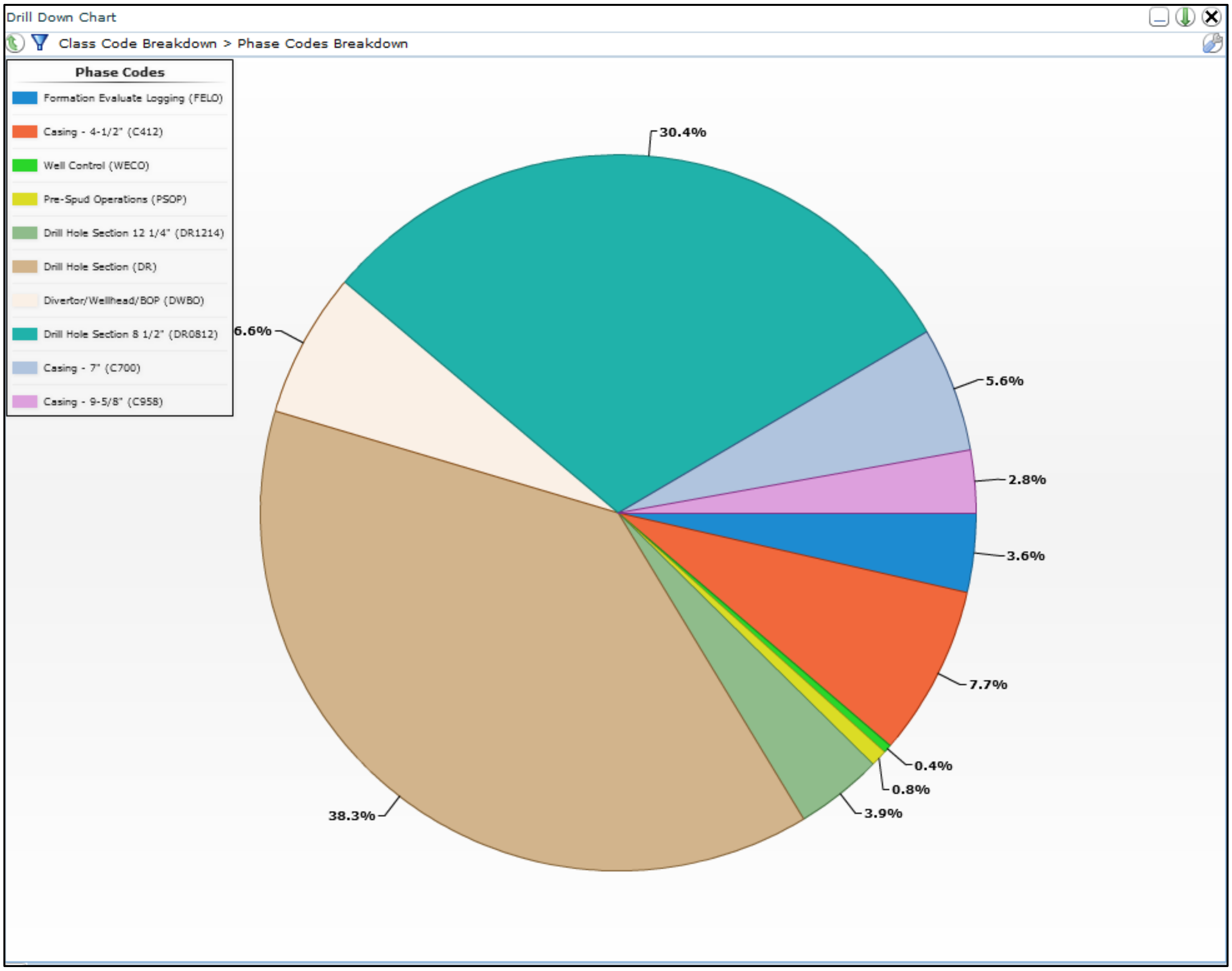

Figure 190: Oil Well #17; Percentage of Programmed Phase Code Breakdown

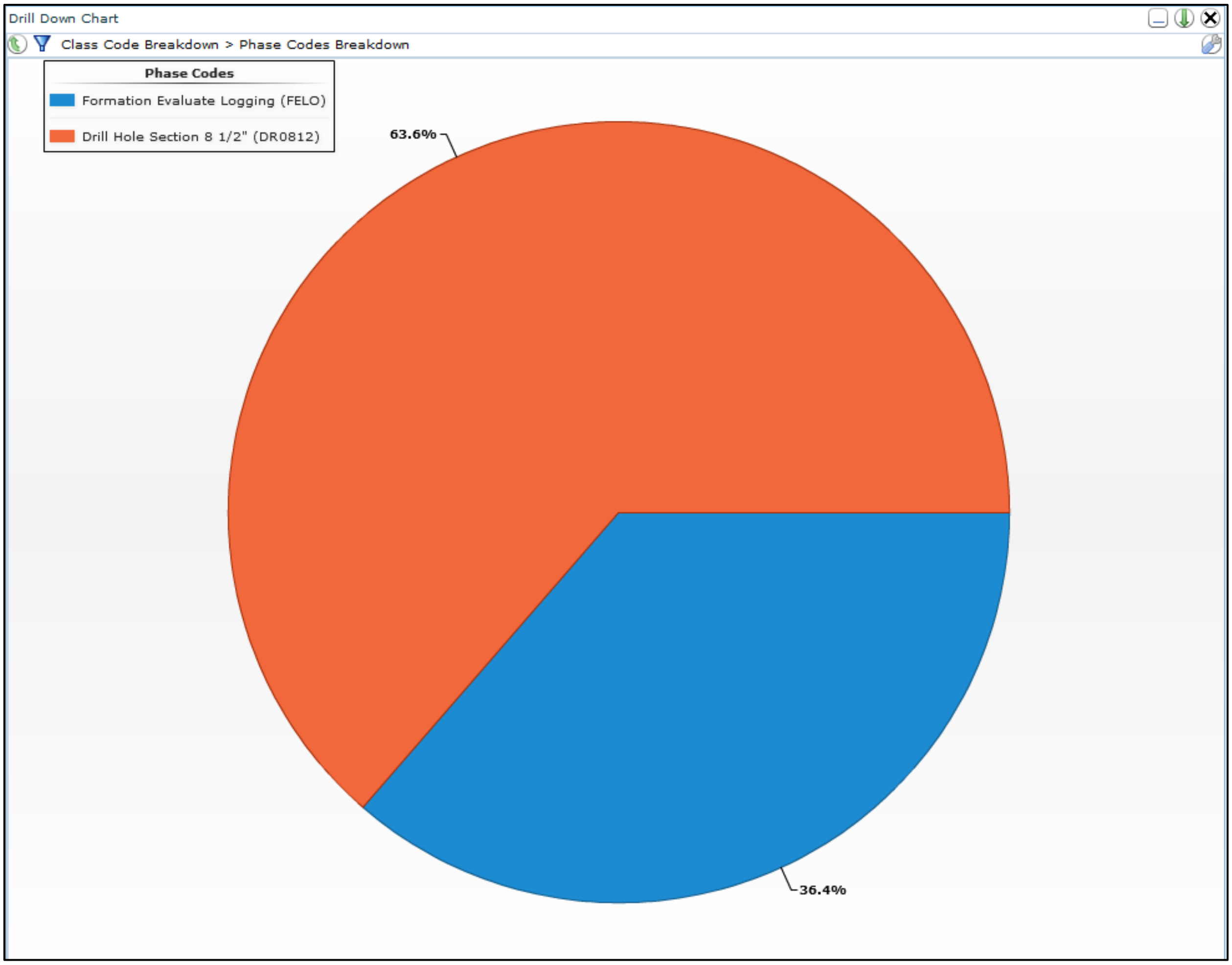

Figure 191: Oil Well #17; Percentage of Trouble During Programmed Phase Code Breakdown

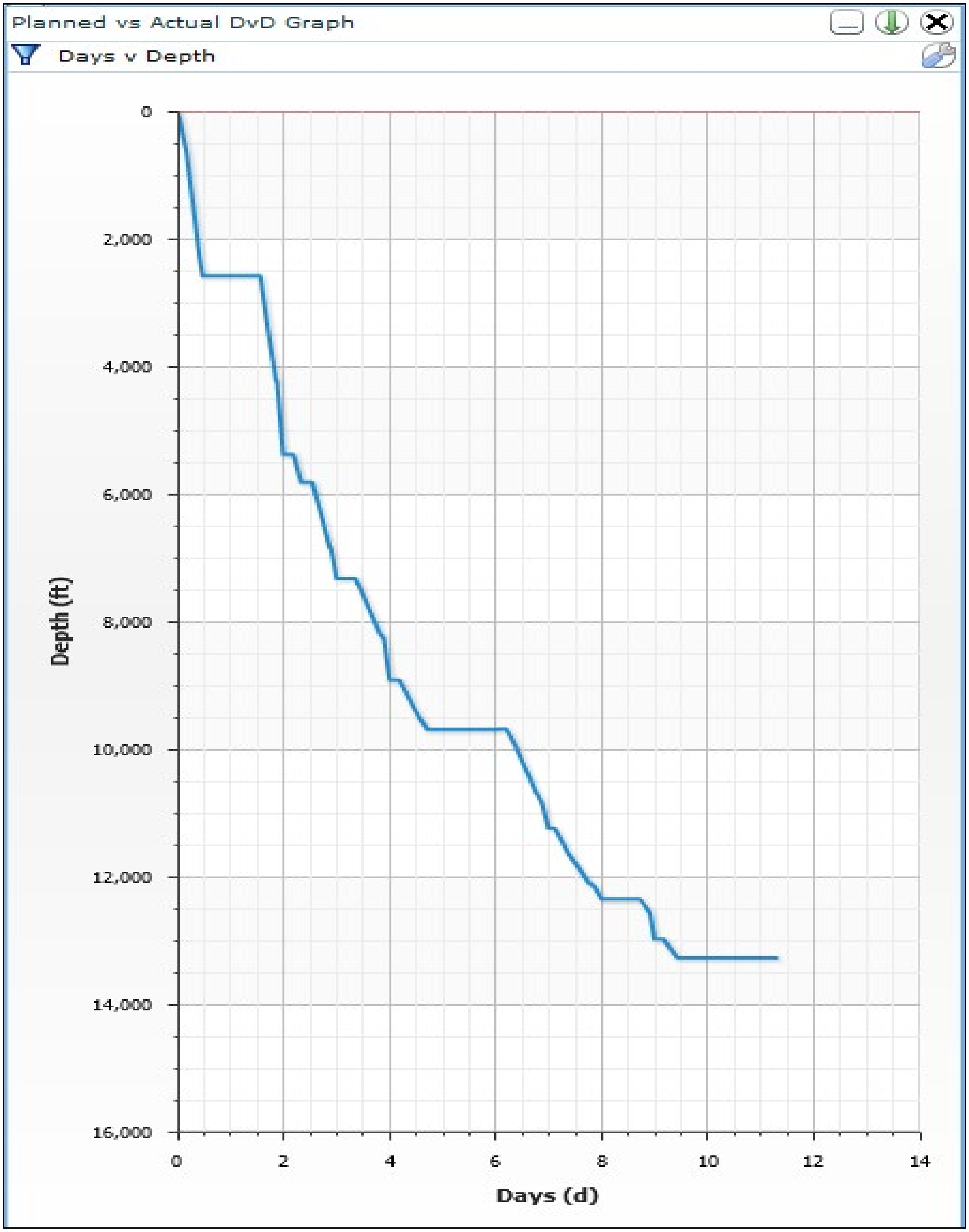

Figure 192: Oil Well #18; Days vs. Depth Drilled

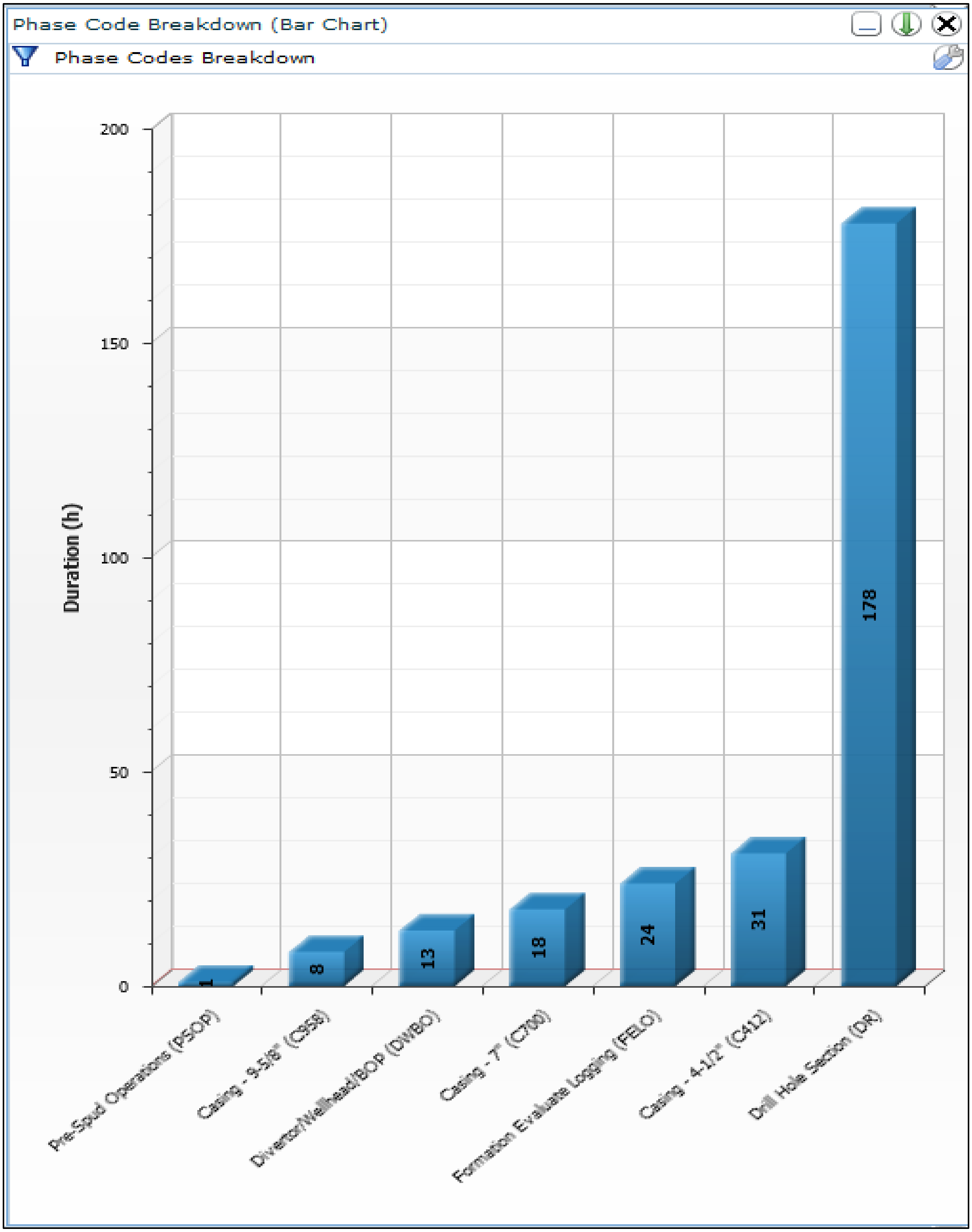

Figure 193: Oil Well #18; Phase Code Breakdown

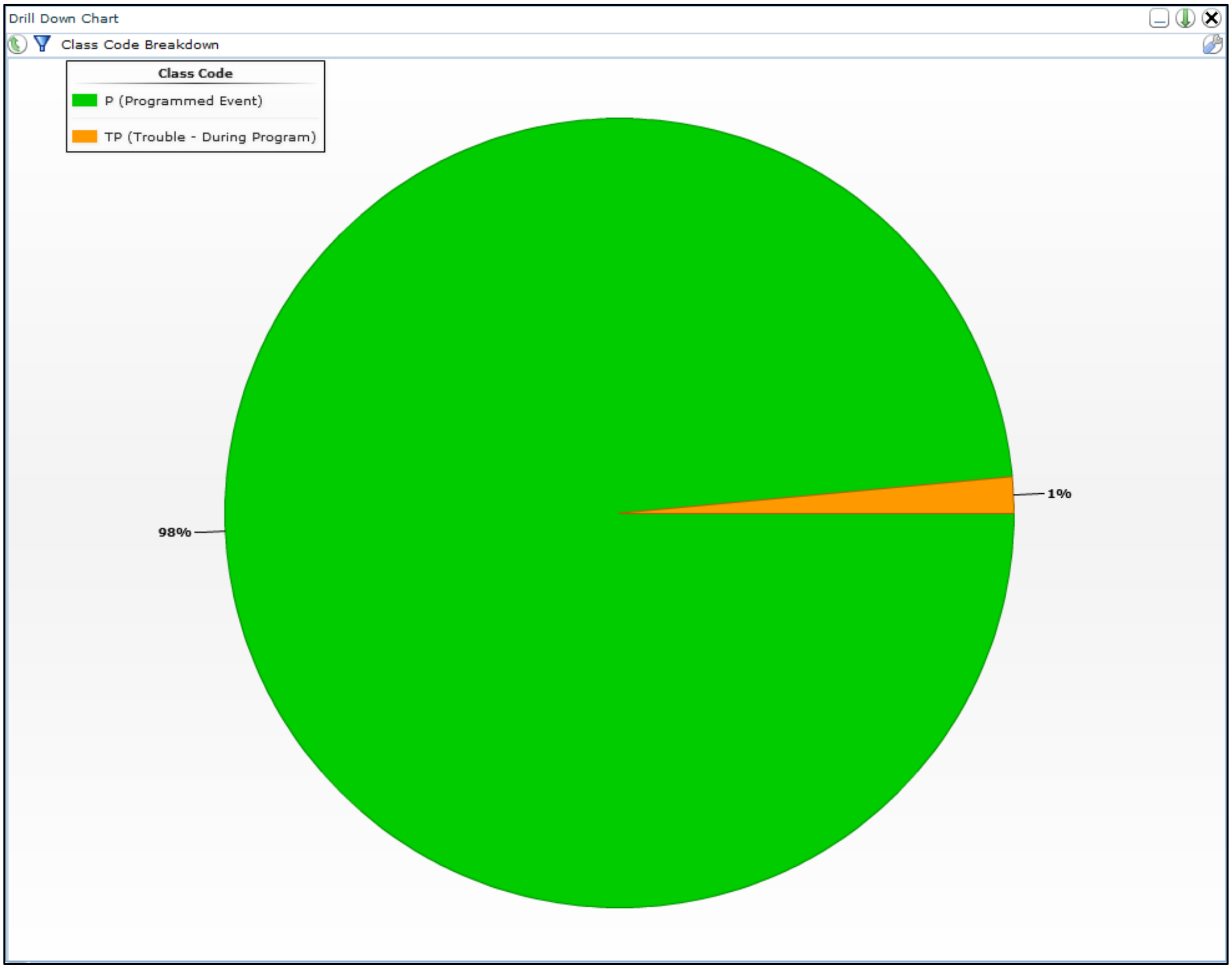

Figure 194: Oil Well #18; Percentage of Class Code Breakdown

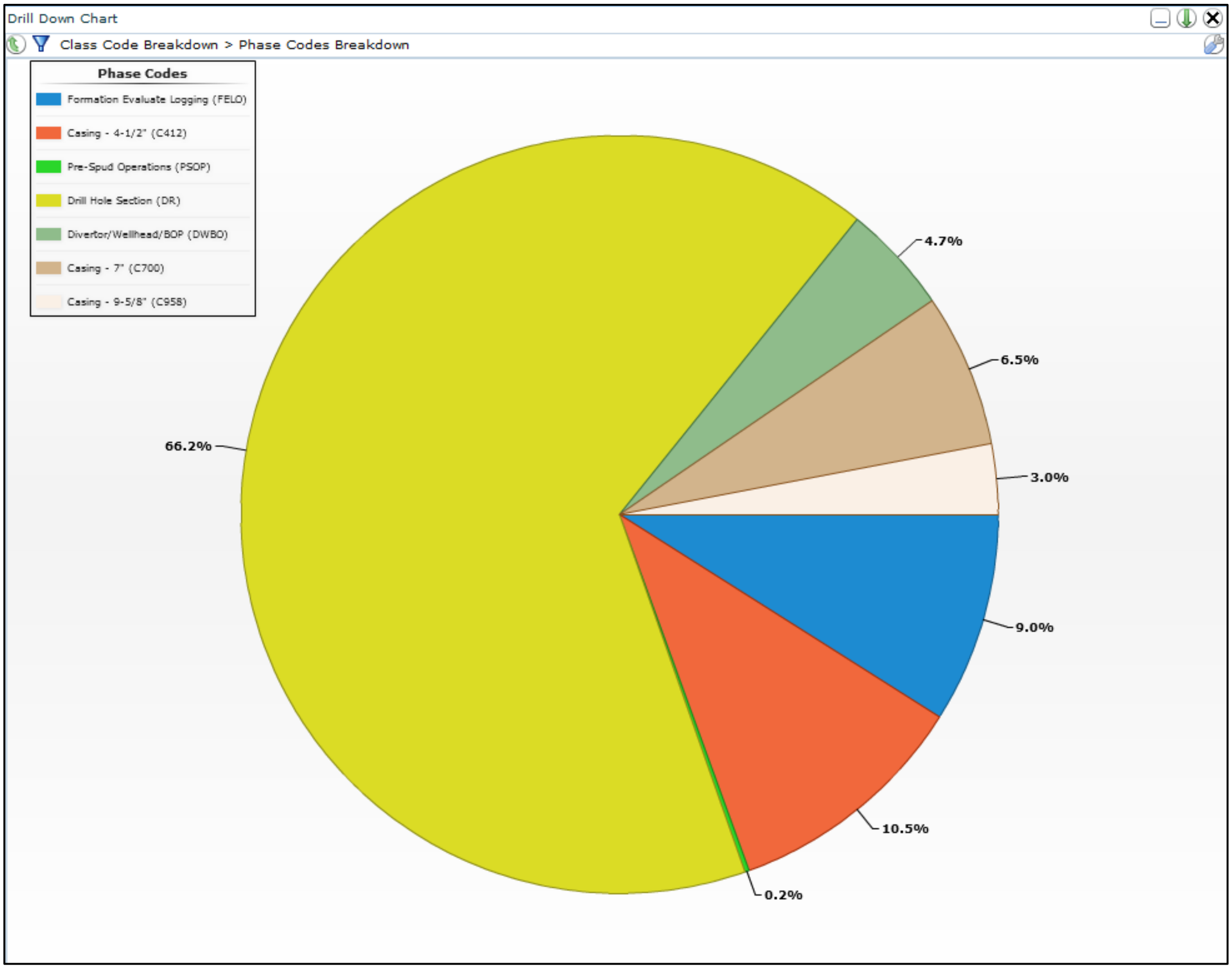

Figure 195: Oil Well #18; Percentage of Programmed Phase Code Breakdown

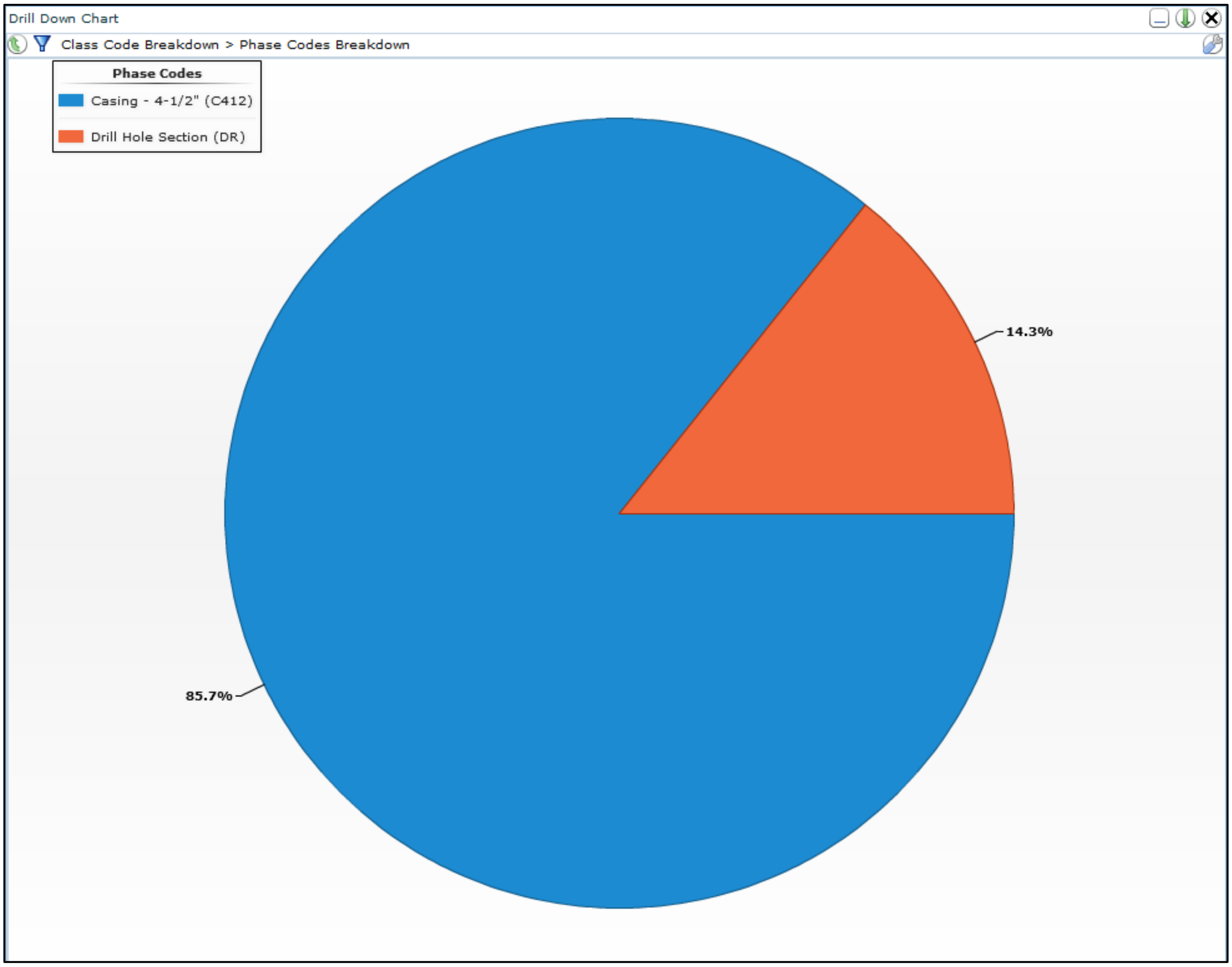

Figure 196: Oil Well #18; Percentage of Trouble During Programmed Phase Code Breakdown

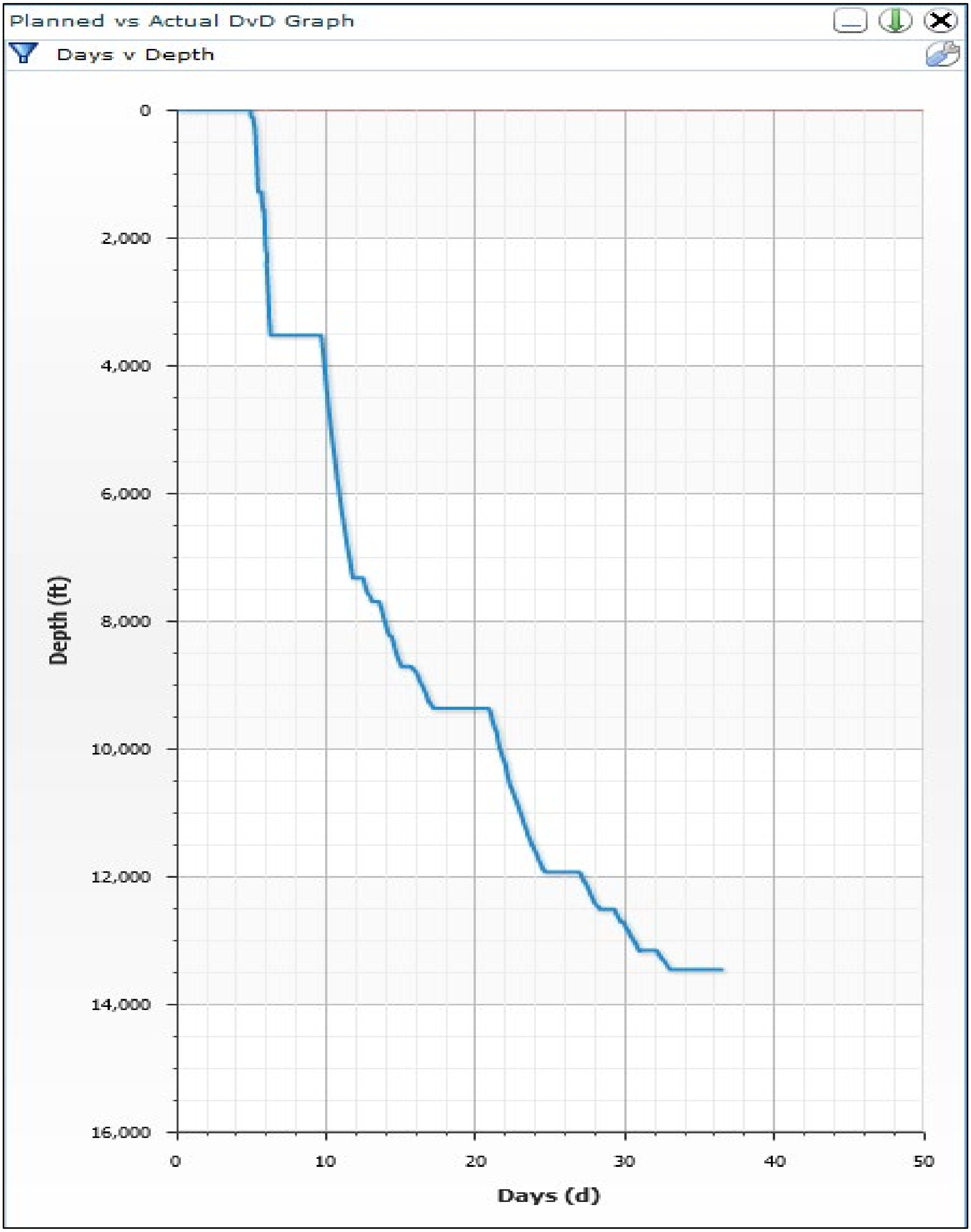

Figure 197: Oil Well #19; Days vs. Depth Drilled

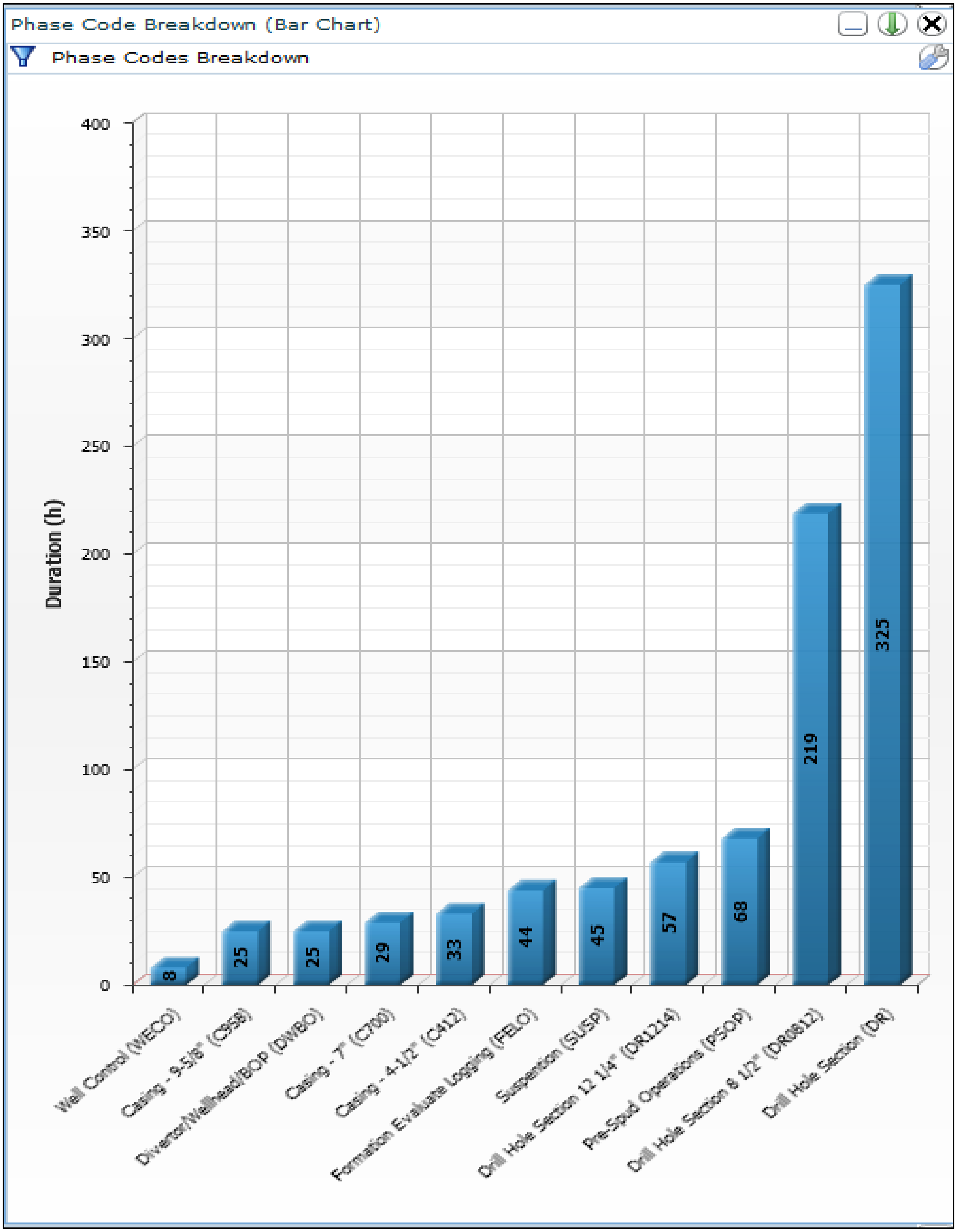

Figure 198: Oil Well #19; Phase Code Breakdown

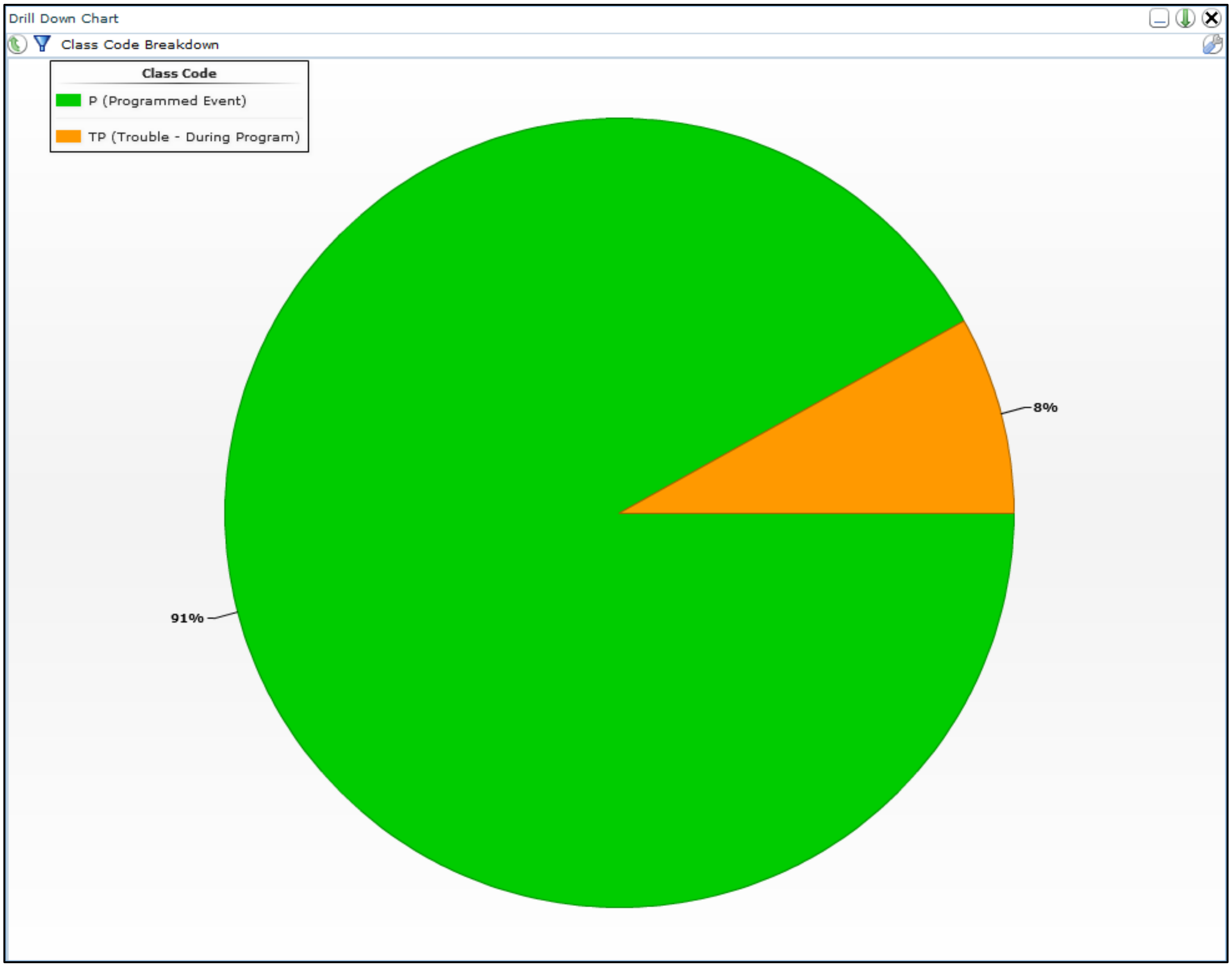

Figure 199: Oil Well #19; Percentage of Class Code Breakdown

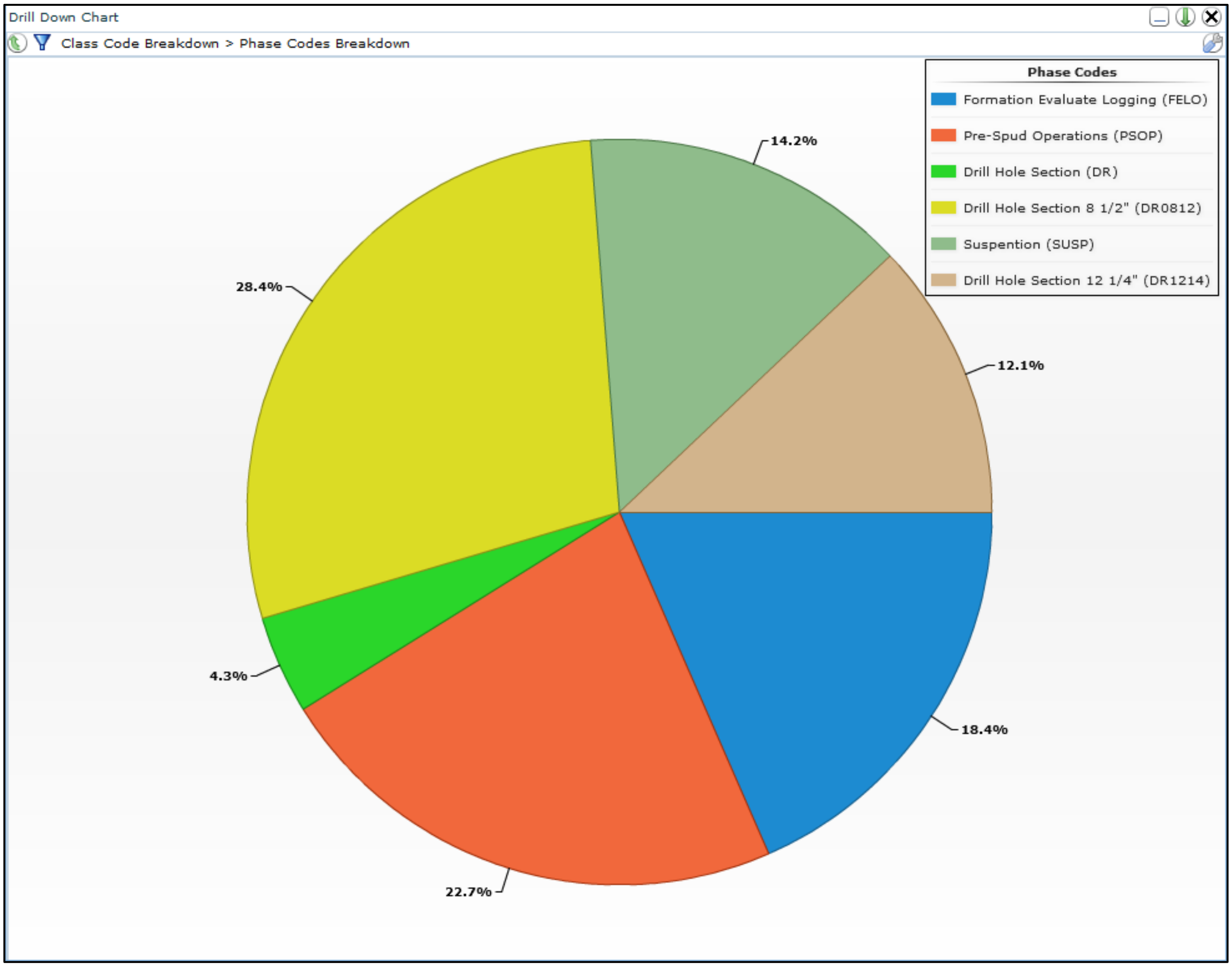

Figure 200: Oil Well #19; Percentage of Programmed Phase Code Breakdown

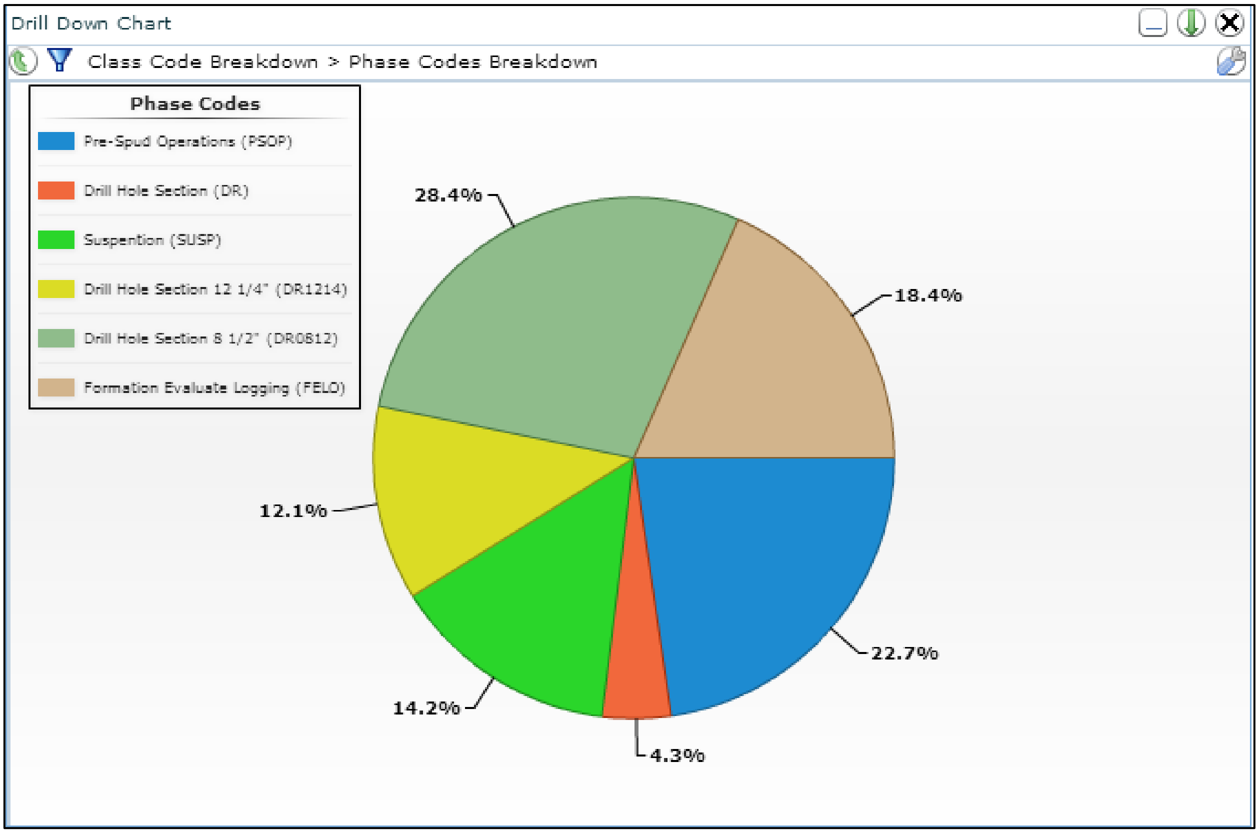

Figure 201: Oil Well #19; Percentage of Trouble During Programmed Phase Code Breakdown

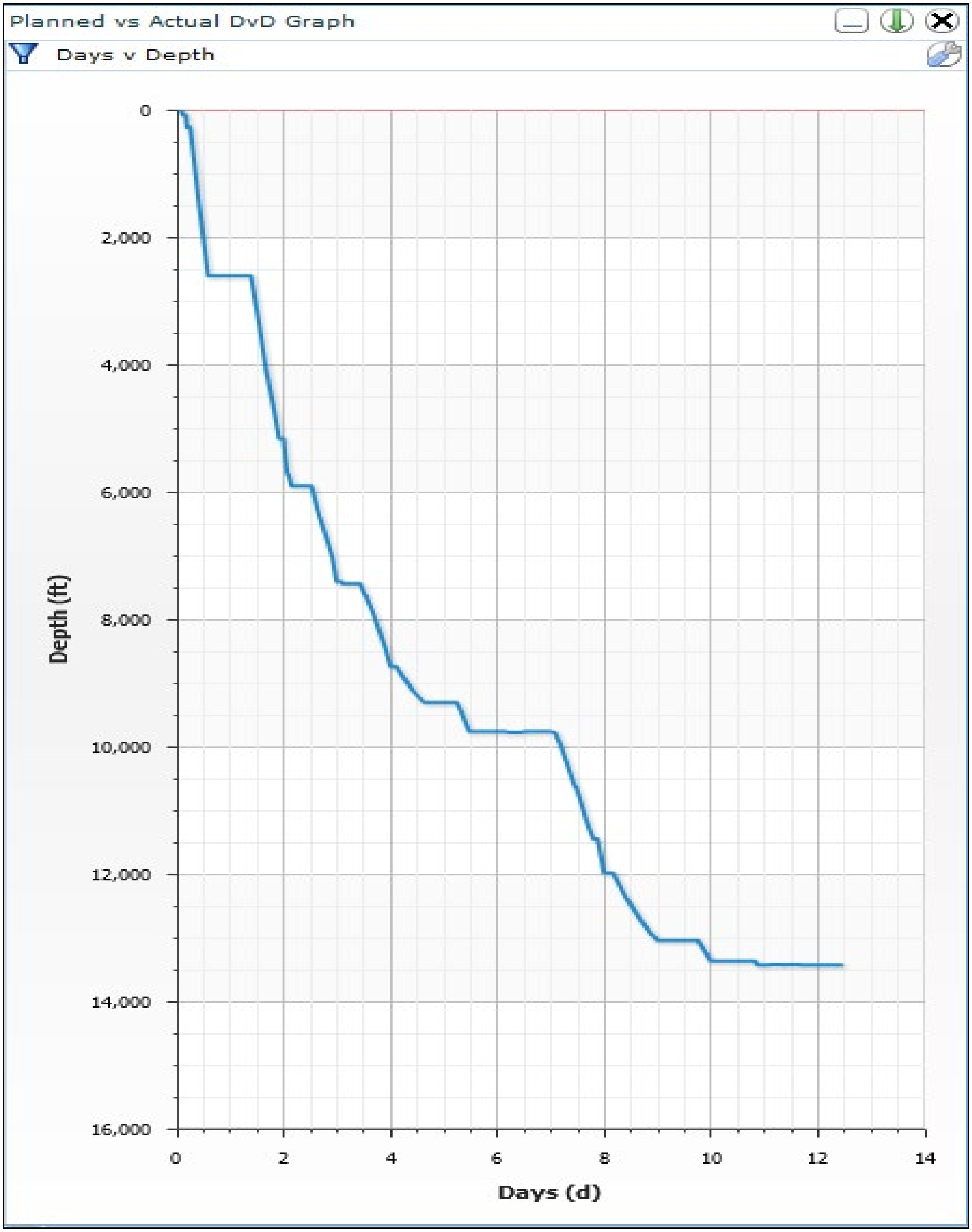

Figure 202: Oil Well #20; Days vs. Depth Drilled

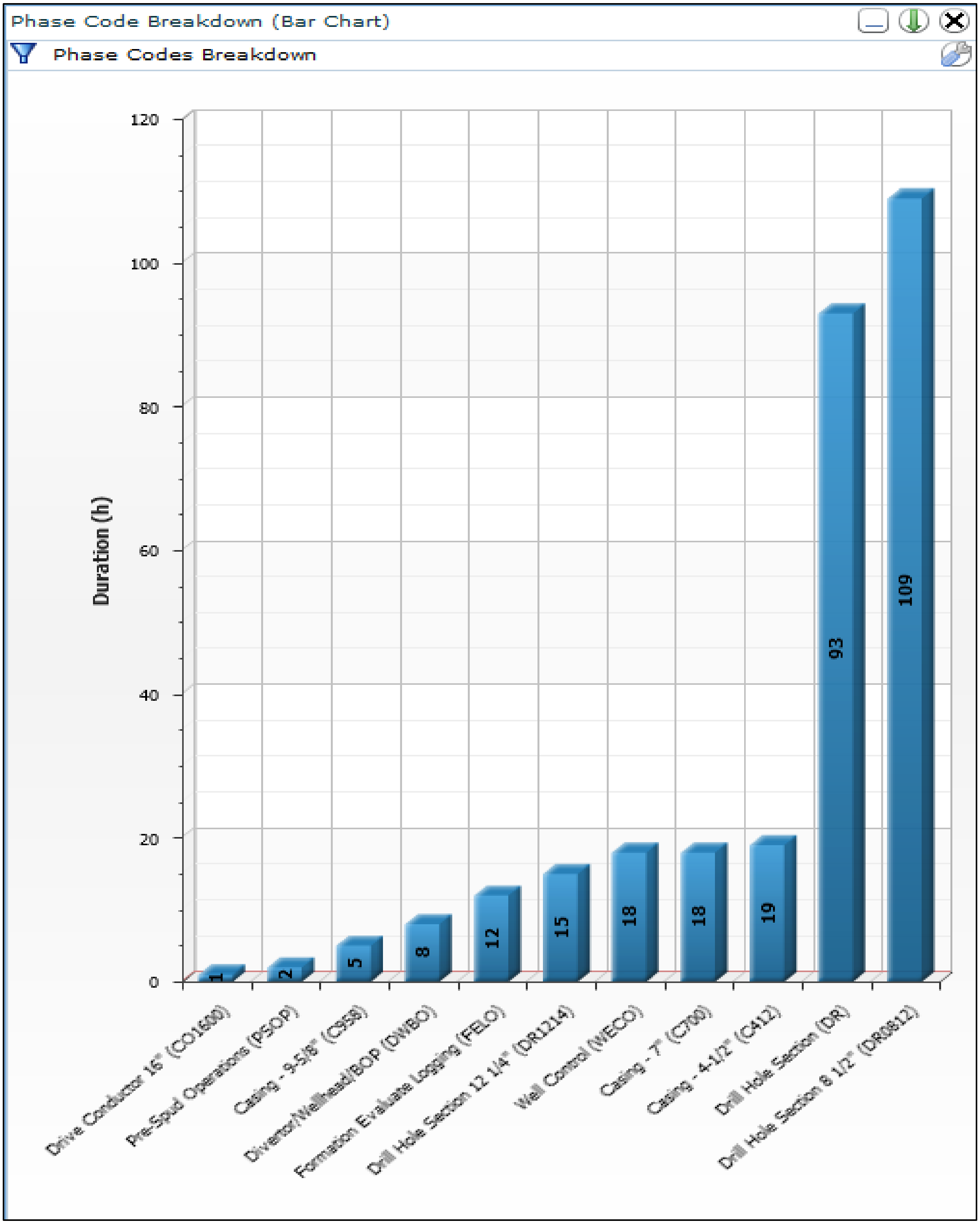

Figure 203: Oil Well #20; Phase Code Breakdown

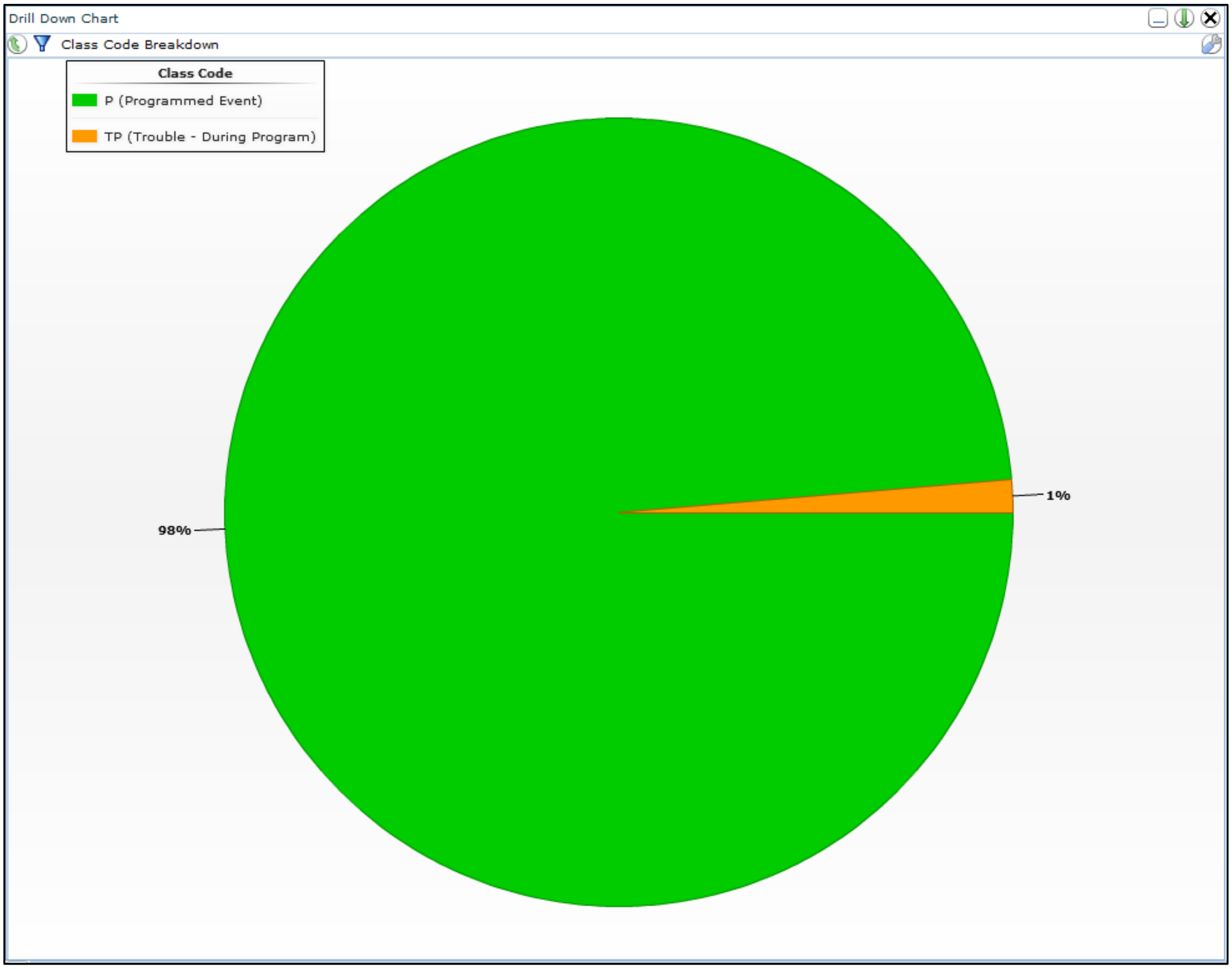

Figure 204: Oil Well #20; Percentage of Class Code Breakdown

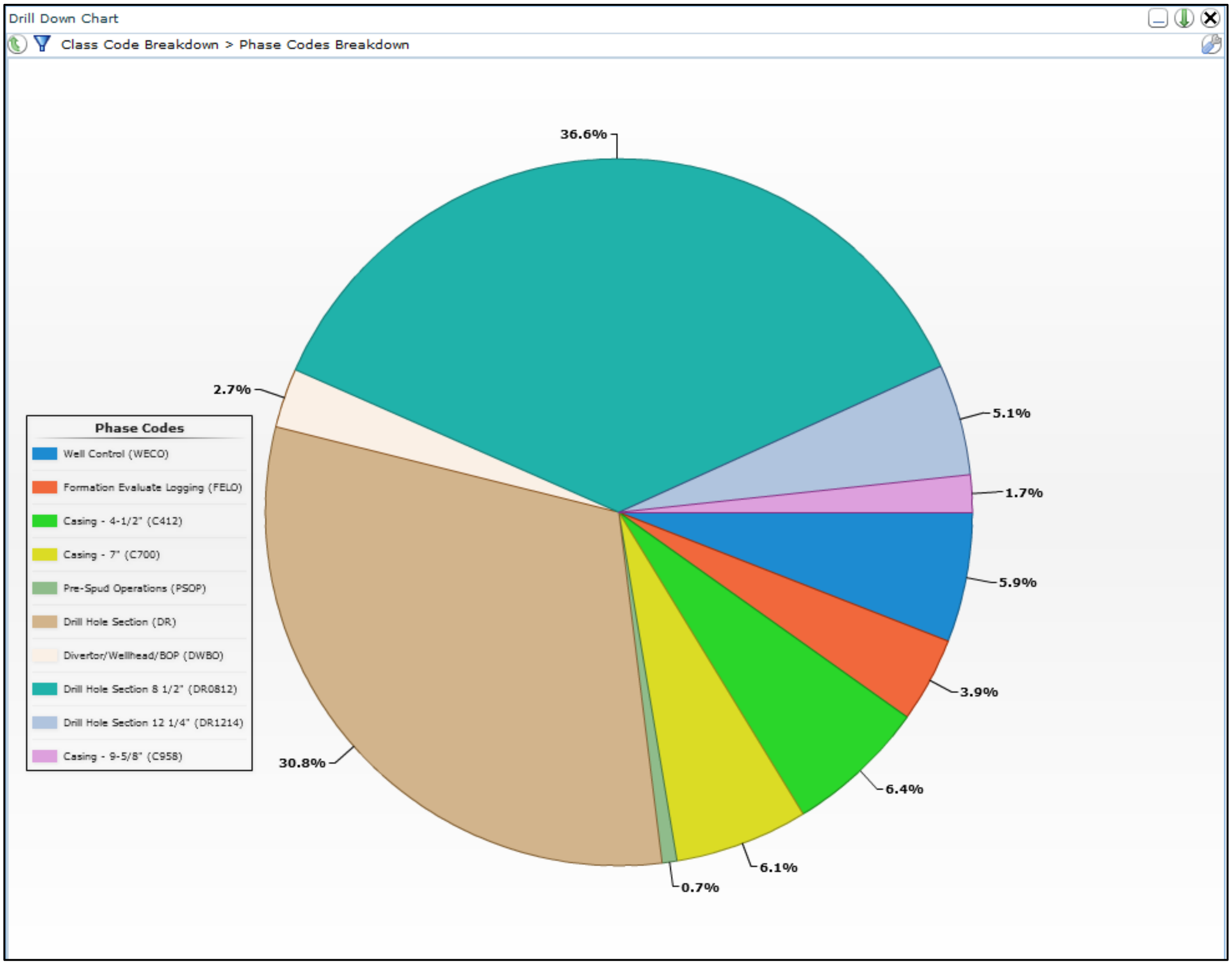

Figure 205: Oil Well #20; Percentage of Programmed Phase Code Breakdown

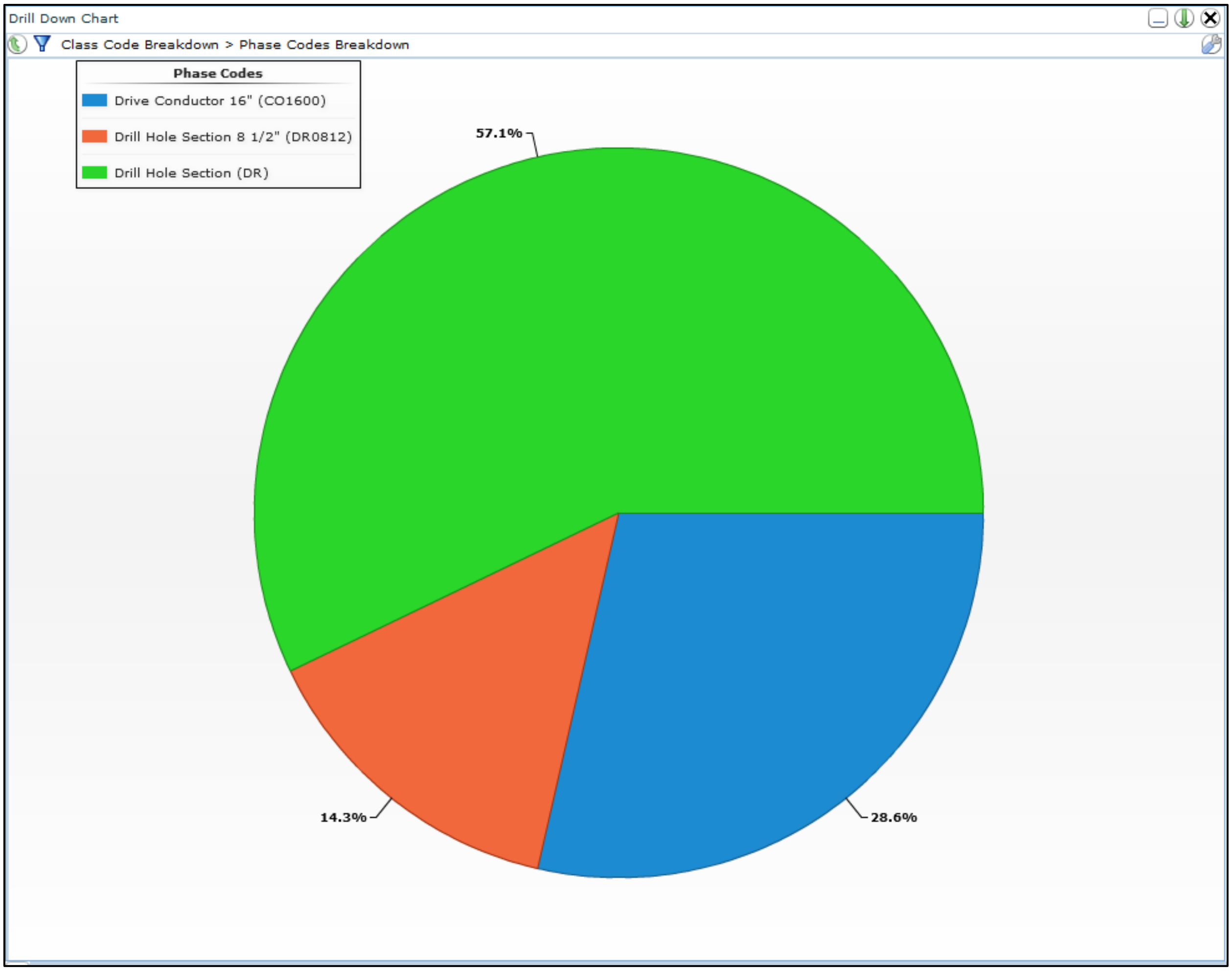

Figure 206: Oil Well #20; Percentage of Trouble During Programmed Phase Code Breakdown

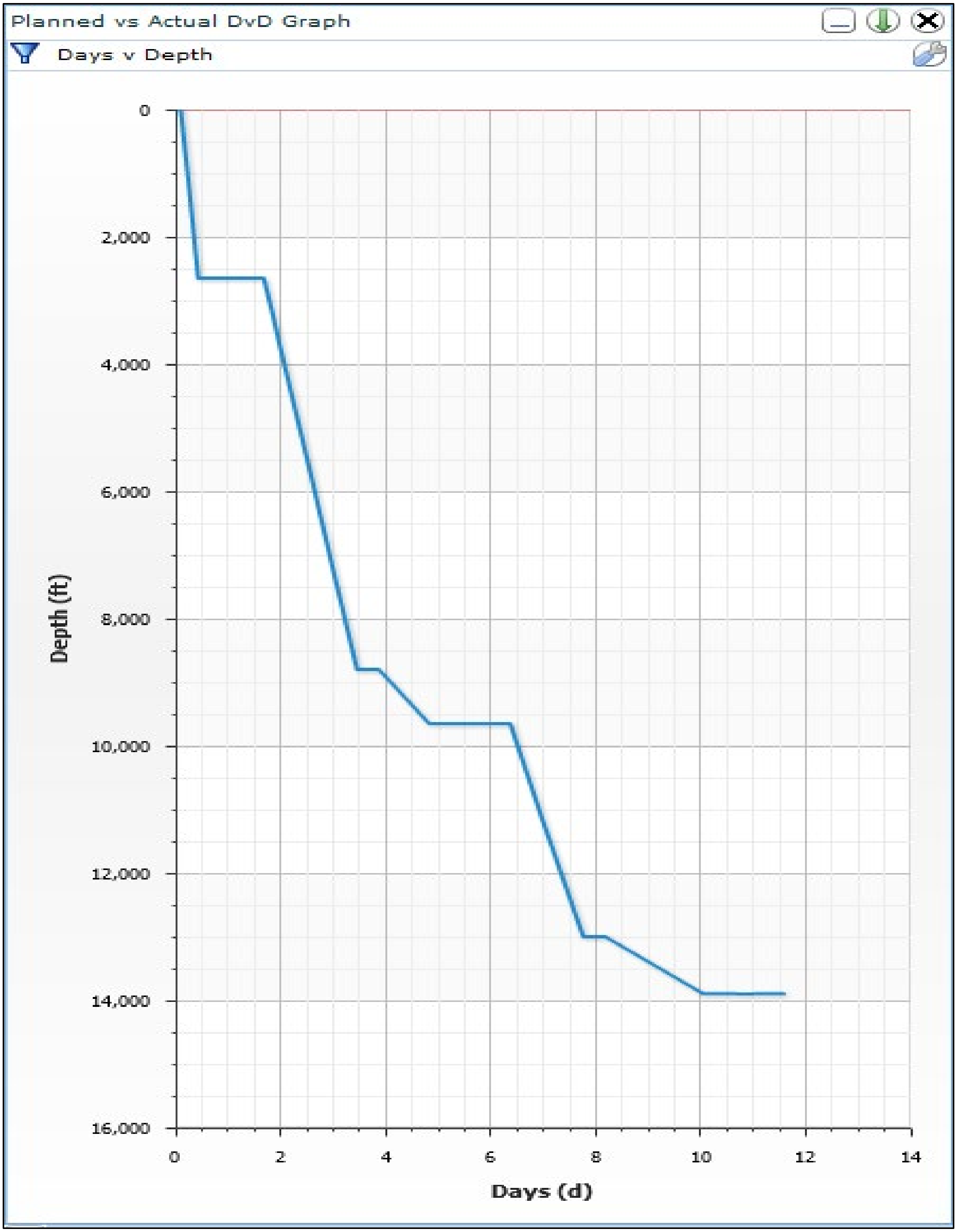

Figure 207: Oil Well #21; Days vs. Depth Drilled

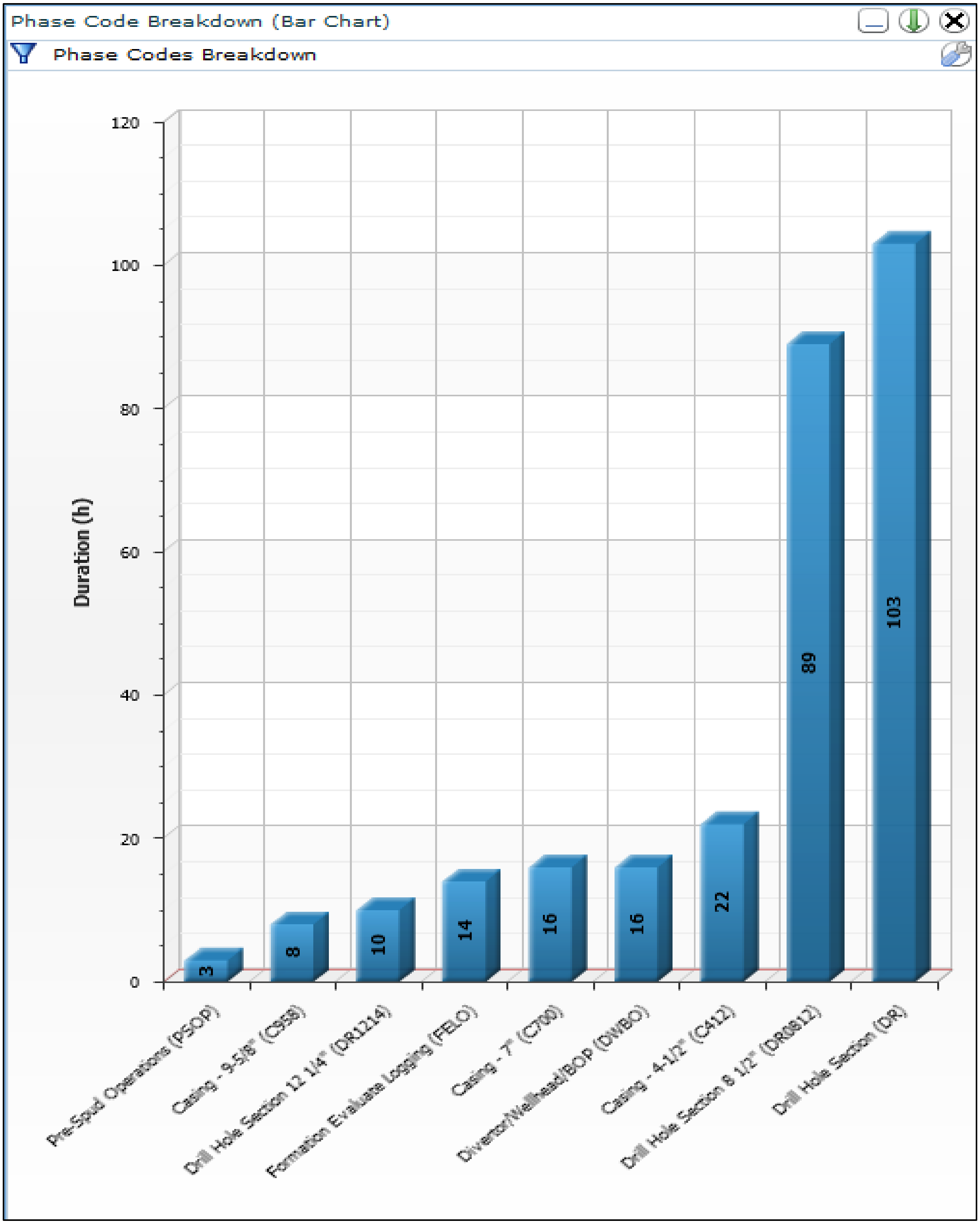

Figure 208: Oil Well #21; Phase Code Breakdown

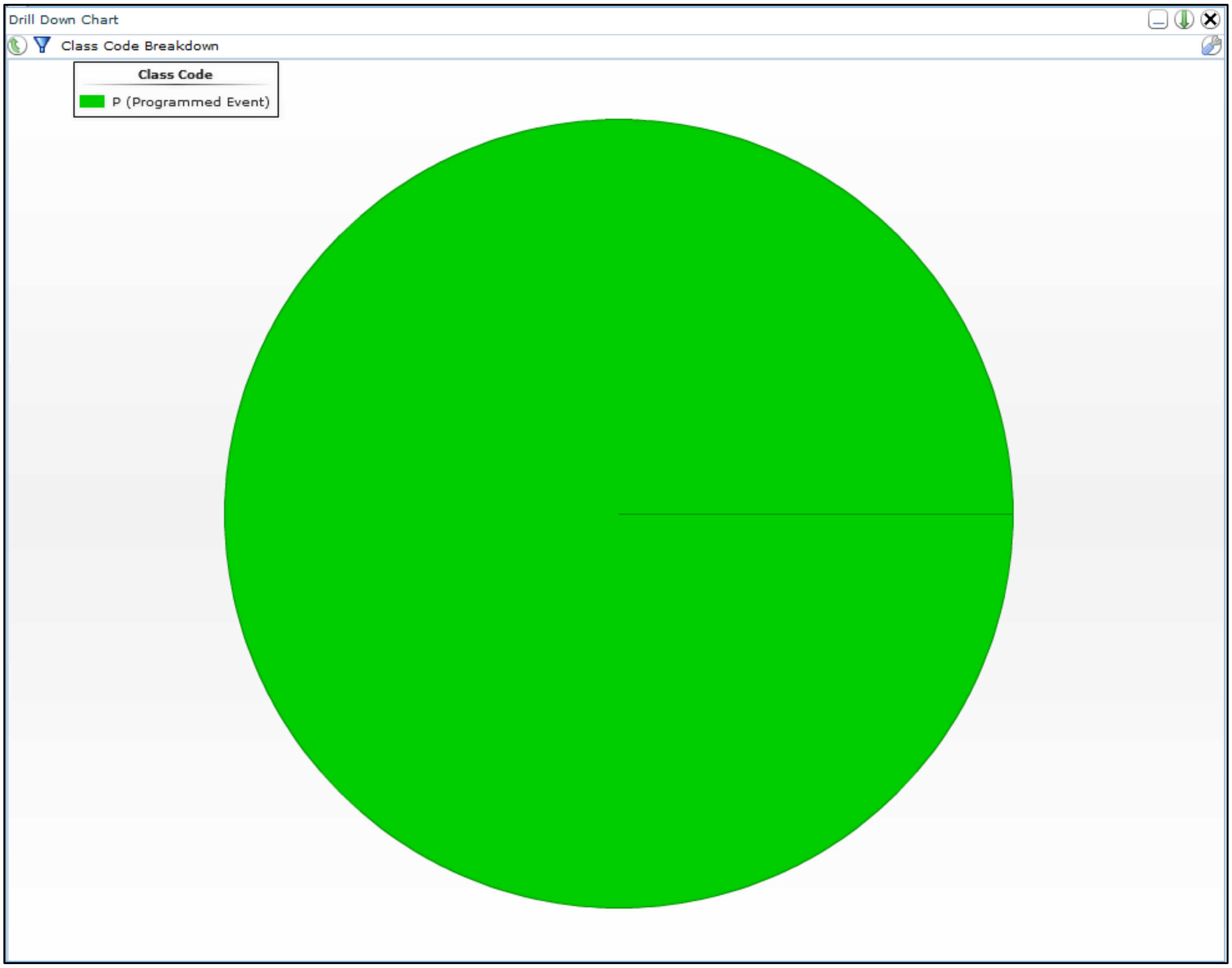

Figure 209: Oil Well #21; Percentage of Class Code Breakdown

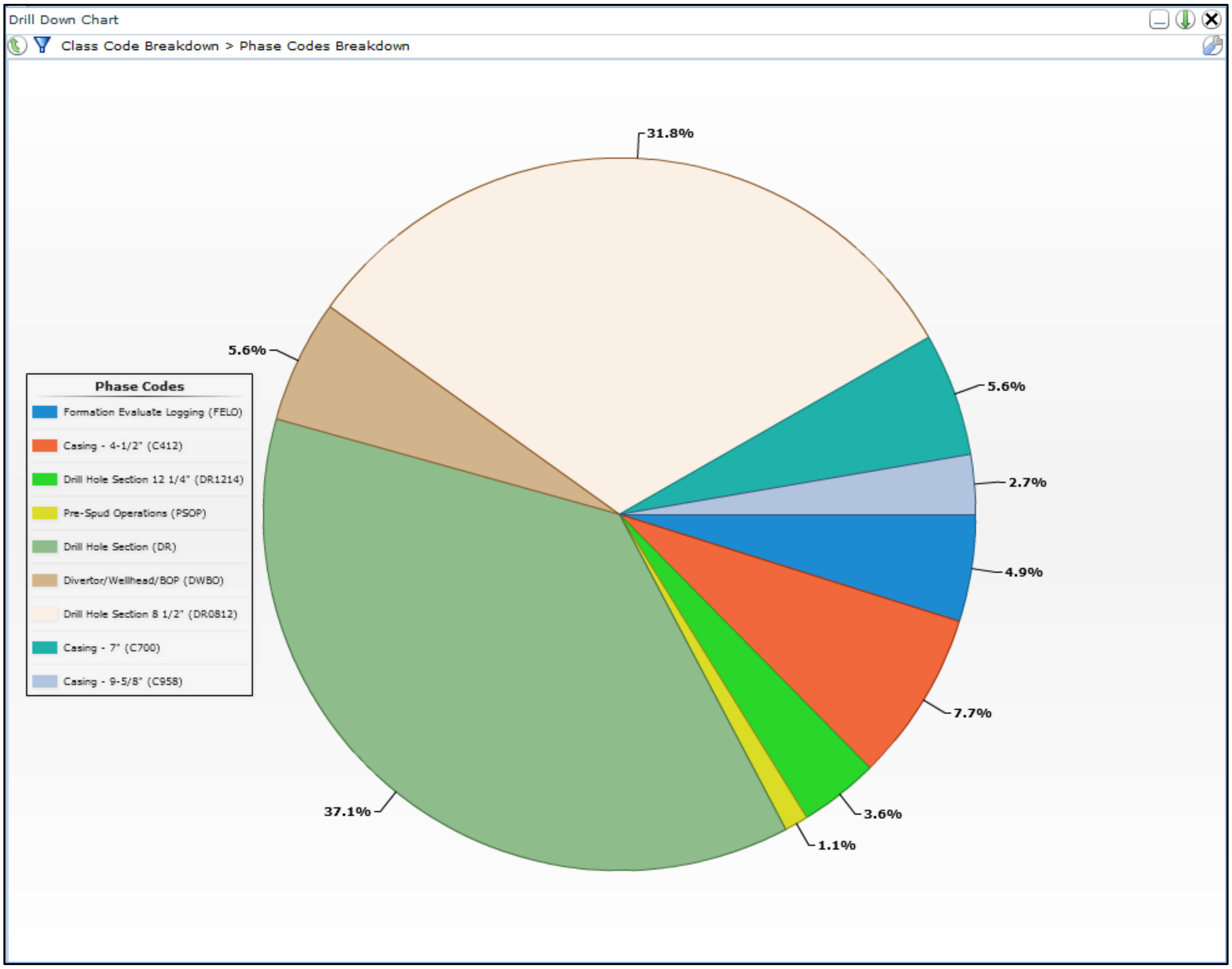

Figure 210: Oil Well #21; Percentage of Programmed Phase Code Breakdown