Second Quarter 2014
Earnings Call
August 6, 2014

<u>Vince White – Senior Vice President, Communications & Investor Relations</u>

Thank you, and welcome to Devon's second-quarter earnings call and webcast. Before we get started, I want to make sure everyone is aware that we have prepared a handful of slides to supplement today's script. The slides are integrated with today's webcast and are also available for download in PDF form on Devon's homepage: devonenergy.com. For those who are not participating via webcast, we will make sure to refer to the slide number during our prepared remarks so that you can follow along.

Today's call will follow our usual format. I will cover a few preliminary items and then turn the call over to our President and CEO, John Richels, for his comments. Then Dave Hager, our Chief Operating Officer, will provide the operations update…and we will wrap up our commentary with a financial review by our CFO, Tom Mitchell. After our financial discussion, we will have a Q&A session. We will conclude the call after one hour, and a replay will be available later today on our website. The Investor Relations team will be available this afternoon should you have any additional questions.

On the call today, we are going to update some of our forward-looking information. In addition to the updates that we are providing in the call, we will file a Form 8-K later today containing the details of our updated 2014 estimates. A copy of this updated 8-K will be available within the Investor Relations section of the Devon website.

The guidance we provide today includes plans, forecasts, expectations and estimates which are forward-looking statements under U.S. securities law. These are, of course, subject to a number of assumptions, risks and uncertainties; many of which are beyond our control. These statements are not guarantees of future performance. For a discussion of the risk factors relating to these estimates see our Form 10-K.

Also in today's call we will reference certain Non-GAAP performance measures. When we use these measures, we are required to provide specific related disclosures. These disclosures may also be found on Devon's website.

As many of you may know, I am retiring from Devon at the end of this week. I can honestly say that being a part of this organization for the last 21 years has been both a pleasure and a privilege. I am truly grateful to all my friends at Devon and in the investment community and the industry for making my time here so rewarding. Thank you!

John Richels – President & Chief Executive Officer

Thank you Vince and on behalf of the company and the many people you have positively impacted over your career I want to thank you. You have done a terrific job through the years and you have been a good friend. We wish you and Marti a very happy and healthy retirement. As many of you know, Howard Thill has joined our team as SVP of Communications and Investor Relations. Howard has a long history in our business with over 30 years of experience, the last 12 in much the same role at Marathon Oil and previously at Phillips Petroleum. We are very fortunate to have an individual of Howard's experience join our team, and we welcome him to Devon.

Moving to the results of the quarter…The second quarter was another outstanding one for Devon, both operationally and financially, as we continued to successfully execute on our strategic plan. Moving to slide on **slide 3**, during the quarter we announced the sale of our non-core U.S. assets, the final piece of our portfolio transformation. Since announcing this planned transformation just nine months ago, we have taken three very significant steps to reconfigure our portfolio: the accretive Eagle Ford acquisition, the unique and innovative EnLink transaction, and the attractive sale of our non-core properties. Also during this time our drilling program has delivered impressive oil production growth by focusing on the reconfigured portfolio. This oil-focused effort helped deliver a 47% increase in cash flow compared to last year's second quarter. And we completed a number of major projects that we'll discuss in more detail during the call.

Now let's take a look at some of these highlights in more detail…

Looking at **slide 4**, in the second quarter, we achieved year over year oil production growth of 34% from our go-forward asset base, reaching an average daily rate of 205,000 barrels per day. This growth was driven entirely by light oil production from our retained U.S. assets, which increased an impressive 79% compared to the second quarter of 2013. This dramatic increase in U.S. oil production is largely attributable to growth from our world-class operations in the Permian Basin and the Eagle Ford. With the aggressive transformation of our North American onshore portfolio, total liquids production is expected to approach 60% of Devon's go-forward production by year-end, up from just over 30% a few years ago.

As shown on **slide 5,** our focus on high margin oil developments increased our companywide oil revenue 42% in the second quarter compared to the previous year and accounted for more than 60% of our total upstream revenue. This strong revenue growth, combined with our low-cost structure, has expanded our pre-tax cash margin per barrel by 40% year over year.

As shown on **slide 6**, and as I mentioned earlier, we announced the $2.3 billion sale of our non-core oil and gas properties in the U.S. during the second quarter. This transaction valued these gas-weighted assets at approximately 7 times EBITDA, significantly above our current trading multiple making it immediately accretive to Devon shareholders. Combined with the sale of our Canadian conventional gas business earlier in the year which was also at about 7 times EBITDA, pre-tax proceeds from our non-core asset divestiture program are estimated to total more than $5 billion. We are applying these proceeds to strengthen our balance sheet by reducing debt taken on to fund our Eagle Ford acquisition.

This portfolio repositioning provides Devon all the necessary attributes to deliver superior per share growth. Our go-forward assets are generating excellent full-cycle returns, we have a strong investment-grade balance sheet, and we have a deep inventory of highly economic low-risk development projects in some of the most attractive basins in North America. As seen on **slide 7**, this formidable and balanced portfolio consists of three world-class oil development plays in the Permian Basin, Eagle Ford, and Canadian oil sands and two of the best liquids-rich gas areas in the U.S.: the Barnett Shale, which is nearly 30% liquids production, and the Anadarko Basin, which is about 45% liquids. We also have two emerging oil plays which could further bolster the depth of our portfolio, and we have a majority ownership in EnLink Midstream, one of the premier midstream companies in North America.

Looking at **slide 8**, with the first six months of results in 2014 now in hand, our retained asset portfolio <u>remains on track</u> to deliver companywide oil production growth of more than 30% year over year. This exceptional oil growth rate is driven entirely by the 70% plus increase we expect in U.S. light oil production. This should drive about 10% top-line production growth on a 6 to 1 energy equivalency basis. On a “value or price equivalent” basis, if you apply a more realistic oil-to-natural gas price ratio of 20 to 1 based on the relative prices the past few years, expected top-line production growth in 2014 to approximate 20%.

Moving to **slide 9**, I’ll remind you that about 80% of our 2014 E&P capital budget is focused on our core and emerging oil development opportunities which will continue to drive our oil production growth in the second half of 2014 as well as next year. You can see on the table to the right, year-to-date we have spent just under half of our

2014 capital budget.

With large, high-quality acreage positions in each of our core assets, we are positioned with a deep inventory of repeatable investment opportunities. In fact, as we discussed on our call last quarter, one of the most exciting operational developments over the past several months has been the significant expansion of Devon's drilling inventory and resource potential in these high-margin core assets. Led by the tremendous results we are seeing in the Delaware Basin, our gross risked undrilled inventory has increased by more than 5,000 locations year-to-date. These 5,000-plus locations have been rigorously risked based on historical well performance, technical evaluations, and disciplined economic expectations based on the current price and cost environment, to mention a few. As we further de-risk and develop the opportunities within our portfolio, we fully expect our inventory to further increase over time. In fact, with the technical work we have done, over the last quarter we have increasing confidence that we can materially grow this inventory in the near future and Dave will speak to this in more detail later.

Not only do we have a large resource base, but we also have the financial capacity to efficiently convert this resource into production and cash flow. Our balance sheet is in terrific shape, and our operating cash flow continues to accelerate thanks to our rapid oil growth driving margins higher. And don't forget that another potential source of cash for Devon is the ability to dropdown midstream assets to EnLink. As seen on **slides 10 and 11**, two potential candidates for such dropdowns are the Access Pipeline in the Canadian oil sands and the Victoria Express Pipeline in the Eagle Ford, both of which were recently completed. These strategically located assets have exposure to two of the fastest growing oil plays in North America. While no decision has been made, these high-quality pipelines could be dropped into EnLink within the next year or two.

Given the visibility of our significant cash inflows coupled with a high-margin asset base ready for development, we expect to accelerate drilling activity in 2015 across several of our core and emerging plays. As you can see on **slide 12**, Devon is positioned to deliver organic oil production growth in excess of 20% in 2015, while delivering a healthy top-line production growth rate in the mid-single digits. The Eagle Ford and Delaware Basin will once again lead our oil production growth in the U.S., and we should also see significant oil growth from our Jackfish 3 project in Canada where we recently started steam injections.

In summary, we are pleased with the execution and outcome of the transformative steps that we took over a relatively short period of time to high-grade the portfolio and meaningfully improve Devon's growth trajectory and margins. When you combine the growth potential of our top-tier oil development projects with our high-quality natural gas optionality, we are well positioned for very competitive growth rates for years to come. As we execute on our growth plan, Devon shareholders will continue to benefit from improving margins, further value recognition from EnLink and higher cash flow.

And with that, I will turn the call over to Dave Hager for a more detailed operations review. Dave?

Dave Hager – Chief Operating Officer

Thank you John. As John mentioned, our solid execution in the quarter resulted in strong oil production growth driving an impressive increase in our operating cash flow. We are laser focused on the key drivers of outstanding operational performance, including driving down drilling times, optimized completion designs and very efficient production operations. Continuous improvements in each of these areas, and others, will provide incremental value in each of our operating areas. Now let's take a closer look at some of Devon's key operating highlights in more detail.

In the **Permian Basin,** we increased production 25 percent compared to the same quarter last year, to 95,000 Boe per day**.** The solid execution of our development programs in the Permian place us firmly on track to grow 2014 production by 20 percent compared to 2013. Importantly, light-oil production accounts for nearly 60 percent of our total Permian volumes.

Shown in the green outline on **slide 13** is the Bone Spring play in the Delaware Basin, a key driver of our Permian oil growth. In the second quarter, we brought 22 new Bone Spring wells online with average 30-day IP rates of 660 BOE per day, once again exceeding our pre-drill expectations. At an average cost of just over $6 million per well, our Bone Spring program is delivering some of the best returns in our portfolio. We also have an ongoing Delaware Sands program that is beating expectations. In the second quarter, we commenced production on two high-rate oil wells targeting the Delaware Sands in Lea County, New Mexico. Initial 30-day production from each of these two wells averaged about 1,000 Boe per day, 70% of which was light oil.

As we discussed last quarter, the tremendous results from our Delaware Basin drilling programs, coupled with our ongoing reservoir characterization work, allowed us to substantially increase our risked undrilled inventory. The stacked-pay nature of our position in the Delaware Basin provides us with exposure not only to the Bone Spring and Delaware Sands, but also the Leonard Shale, Wolfcamp and several other oil zones. In aggregate, our multi-zone potential in the Delaware Basin provides us with exposure to more than 5,000 risked undrilled locations.

Turning your attention to **slide 14,** I want to be clear, this inventory of 5,000 plus locations is not simply acreage divided by an arbitrary well spacing. We screened these locations based on multi-variant analysis that takes into account geologic, geophysical, completion and production data to characterize and predict reservoir performance. This disciplined methodology is utilized across our entire portfolio including the Delaware Basin to identify and quantify undrilled inventory.

Slide 15 provides a summary of the risking applied to each of our prospective zones in the Delaware Basin. In the second column, our technical teams have identified net prospective acres in each formation in the Delaware Basin. Next, the multi-variant analysis I just described was performed by our technical teams which risked these prospective acres by as much as 50%. There is insufficient data to do a multi-variant analysis on downspacing, so you can see we conservatively assumed only 4 to 5 wells per drillable section in each formation. We believe there is meaningful upside to our inventory. For example, we are currently implementing a program in the Delaware Basin that utilizes a much larger and more focused frac design that will deliver a more complex fracturing network closer to the wellbore. We believe these larger, more complex frac designs will more effectively drain the reservoir, increase recovery factors, and further enhance rates of returns. In conjunction with these larger, more complex frac tests, we are evaluating the concept of a staggered lateral development scheme that could further tighten well spacing across our prospective formations in the Delaware Basin and thus could significantly increase our risked, undrilled inventory. We will continue to update you on our progress in the coming quarters.

Converting this massive and growing opportunity in the Delaware Basin into production and cash flow is a top priority for us. While not finalized, our preliminary plan is to increase our operated rig count from the 12 currently running in the Delaware to as many as 20 by the end of 2015. We plan to ramp-up activity in an orderly fashion as we secure gathering and processing capacity, high-quality rigs, completion services and manpower to support the higher rig count. This increased investment in the Delaware Basin will allow us to continue aggressively developing our highly profitable Bone Spring inventory and accelerate the development and appraisal of our Delaware Sands, Leonard Shale, and Wolfcamp inventories. This sets up our prolific Delaware Basin position for significant high-margin growth in 2015 and for years to come.

Shifting to the **Midland Basin**… we delivered another quarter of strong results from our oil development program in the Southern Midland Wolfcamp Shale. We increased average net production in this play to 12,000 Boe per day, representing a significant year-over-year increase of 9,000 Boe per day. In the Northern Midland Wolfcamp trend, we spud our first horizontal well in Martin County targeting the Wolfcamp B formation in the third quarter. We have approximately 14,000 net acres in the prolific Martin County area prospective for multiple Wolfcamp zones. In aggregate, we have identified around 200 undrilled locations in the Northern Midland Wolfcamp trend and this is an area likely to see increased activity as we head into 2015.

Shifting to the **Eagle Ford and slide 16**… While we have only owned these assets for a handful of months, we could not be more pleased with the performance we have seen from this world-class asset. And, we have already identified several promising opportunities that could further enhance well economics and boost our drilling inventory. I will speak to this in more detail shortly, but let's begin with a review of second quarter results.

During the quarter we had 17 rigs running across our Eagle Ford position, with the majority focused on developing our DeWitt County acreage in the economic heart of this top-tier oil play. We brought 60 new Eagle Ford wells online with average 30-day IP rates approaching 1,200 Boe per day. These high-impact wells drove our average Q2 production in the Eagle Ford to 65,000 BOE per day, in line with the guidance range we provided last quarter. Notably, we achieved this strong growth in spite of production interruptions primarily related to third-party gathering system constraints in DeWitt County. In aggregate, these gathering constraints reduced production by approximately 8,000 Boe per day in the quarter. Even with these infrastructure limitations, we were able to bring approximately 30 wells online around mid-quarter that helped accelerate our average net production in June to 73,000 Boe per day. This ramp-up in June represents an impressive increase of nearly 50 percent compared to the first-quarter exit rate. It is also worth mentioning that our Eagle Ford production is also delivering the highest pre-tax cash operating margin of any asset in our portfolio at around $60 per Boe.

Looking ahead to the second half of the year, our drilling and completion programs in the Eagle Ford remain on schedule, keeping us on track to deliver outstanding production growth rates. As we have said before, this production can be somewhat lumpy due to the timing of pad drilling and third-party midstream infrastructure. At June 30th, we had 108 drilled wells not yet producing. We expect this inventory to continue to trend downward over the coming months as a number of pads are scheduled for tie-in and the necessary transportation system improvements are completed in DeWitt County. As a result, for the remaining six months of 2014, we are forecasting our net Eagle Ford production to average between 80,000 and 85,000 BOE per day. We expect both the third and fourth quarters to generate solid sequential quarter production growth, with volume growth weighted more toward the fourth quarter due to the timing of pad tie-ins that I just mentioned. Overall, this second half outlook keeps us on pace to deliver on our previously announced guidance of 70,000 to 80,000 BOE per day for our ten months of ownership this year.

As I touched on earlier, we are also excited about a number of potential upside opportunities we have identified across our position in the Eagle Ford. In our development activity in DeWitt County we are working closely with our partner BHP to enhance various aspects of our well completions, as well as areas on the production operations side of the business. While it is premature to discuss any specific details, the technical teams have identified opportunities to optimize completion designs that could increase well recoveries and at the same time reduce well costs. The teams have also identified potential opportunities to improve the rates of return through optimized choke management. As we continue to pursue these promising initiatives we will continue to update you on our progress.

Moving to **slide 17,** another leg of upside is in **Lavaca County**. In the second quarter, we tied-in our first operated well in Lavaca County targeting the Lower Eagle Ford formation. As seen in blue on the map, initial 24-hour production from the Ronyn 1H was approximately 1,600 Boe per day, of which 70% was light oil. Combined with announced wells by industry represented in grey, Lower Eagle Ford results to date in Lavaca County have exceeded our initial expectations.

Turning your attention to **slide 18,** perhaps one of our more exciting potential upside opportunities is the **Upper Eagle Ford.** As shown by this isopach map, the majority of our DeWitt and Lavaca County acreage is highly prospective for this emerging play. This is further supported by the encouraging industry results in Lavaca County, seen in grey on the map. It is worth noting these Lavaca County well results are not in the thickest part of the Upper Eagle Ford, which as you can see from the map bodes well for the prospects of our DeWitt County acreage where the Upper Eagle Ford net pay is the thickest. We have just spud our first operated Upper Eagle Ford well, the Medina

2H, on 100% working interest acreage in north east DeWitt County. This can be seen in blue on the map. This is the first of a handful of tests planned this year. If the Upper Eagle Ford formation is commercially successful this could expand Devon's resource and further deepen our drilling inventory.

On **slide 19**, at our **Jackfish thermal oil projects** in northeastern Alberta…gross production from our Jackfish 1 and Jackfish 2 projects increased 3% year-over-year to a combined average of 60,000 barrels of oil per day, or 52,000 barrels per day after royalties. Further enhancing results, the significant improvement in Western Canadian Select benchmark pricing increased price realizations at Jackfish by a 22 percent compared to the year-ago quarter to $65.88.

At **Jackfish 1** gross production averaged 36,000 barrels per day or 29,000 barrels per day, net of royalties in the second quarter. The success of our ongoing efforts to improve our steam-oil-ratio once again resulted in gross production exceeding the facility's name plate capacity of 35,000 barrels per day. In the third quarter, we will bring the Jackfish 1 plant down for a scheduled two week maintenance turnaround beginning in September. Accordingly, this maintenance downtime and subsequent ramp-up will reduce Jackfish 1 production by 5,000 to 10,000 barrels per day in the third quarter. Keep in mind this has been built into our third-quarter and full-year production guidance.

At **Jackfish 3,** we began steaming on July 13th and expect a steady ramp-up of production over the next 18 months to a sustained rate of 35,000 barrels a day.

Jackfish 3 will provide multi-year oil production growth beginning in 2015, with net oil production from our Jackfish complex expected to be between 62,000 to 67,000 barrels per day. This represents production growth of about 30% compared to 2014. Furthermore, as seen on **slide 20,** the completion of Jackfish 3 will begin an era of free cash flow from our Jackfish complex with the potential to generate around $1 billion annually for many years, even after accounting for maintenance capital requirements.

Shifting now to the **Anadarko Basin** in western Oklahoma where our operations continue to deliver great results. In the second-quarter, we once again set a production record, reaching 93,000 Boe per day. With drilling focused on our most liquids-prone acreage, oil and NGL production increased 26% year-over-year and now is about 45% of production in the Anadarko Basin.

The **Cana-Woodford** play was the most significant contributor to our strong second-quarter production growth in the Anadarko Basin. This growth was driven by the strong performance of several new well pads brought online that employed our new, redesigned completions as well as rejuvenated performance from existing wells as a result of our ongoing acid treatment program.

Slide 21 shows the meaningful increase in sand per well, along with more frac stages and tighter perf clusters. This new frac design was utilized on the 20 Cana-Woodford wells we brought online, in the liquid-rich core of the play, during the second quarter. Initial 30-day rates from these wells averaged 1,250 Boe per day, including

700 barrels of liquids per day, exceeding our type curve by more than 35 percent. These are among the most productive wells ever drilled in Cana, with average EURs trending in excess of a million and a half equivalent barrels per well. As you can see on **slide 22**, for the 20 wells we brought online in Q2, the redesigned completions dramatically enhanced IP's, boosted EUR's by more than 15% and with well costs essentially flat. This translates into strong rates of return that are competitive with many U.S. oil plays.

Our asset team at Cana have also done some outstanding work to revitalize production from existing wells with acid treatments. We have now treated nearly 200 operated and non-operated Cana wells and the results have been exceptional. In most cases this inexpensive procedure, around $250 thousand per job, took production per well from around 1 million cubic feet equivalent per day to 2 million a day or more. As seen on **slide 23**, these acid jobs have improved our gross operated wet gas production at Cana by roughly 40 million cubic feet a day. We expect about a BCF per well of additional recovery, with a payback period of less than 3 months. We have around 140 additional operated and non-operated wells that can be treated in the core area, and we expect to have most of these treated by year-end.

Moving to **slide 24**…Given the success of these recent efforts at Cana, we opportunistically bolstered our leasehold position in May by acquiring an additional 50,000 net acres in the core of the play. This transaction closed in late June, increasing our total Cana-Woodford position to approximately 280,000 net surface acres with stacked-pay potential, including about 30,000 net acres of exposure to the

STACK oil and condensate window. The new acreage further supplements the thousands of undrilled locations we have in this high-quality, liquids-rich play.
Due to the highly competitive economics at Cana, we plan to accelerate activity in 2015. If you were to include the non-operated activity of our partner in the play, our total rig count at Cana could be around ten rigs by the first quarter of 2015. This increased activity puts Cana in the position to continue to deliver strong growth for many years.

Moving to **slide 25**, we have approximately 150,000 net surface acres in the Powder River Basin prospective for multiple formations including the Parkman, Turner and Frontier. To date, we have identified approximately 1,000 risked locations across our Powder River Basin position, with roughly 75% of these locations associated with the Parkman formation. Our recent drilling activity was highlighted by two wells targeting the Parkman formation in Campbell County, Wyoming. Initial 30-day production from each of these wells averaged 950 Boe per day, of which 95 percent was light oil. At an average well cost of only $5 million per well, our Parkman program is generating attractive rates of return. We expect to add a fourth rig later this year and more aggressively develop the Parkman Focus area in the second half of 2014 and 2015.

With that, I will turn the call over to Tom for the financial review and outlook. Tom?

Tom Mitchell – Executive Vice President & Chief Financial Officer

Thank you, Dave and good morning everyone. To reiterate John and Dave's comments, the second quarter was one of strong execution. We delivered operationally by successfully exploiting the high-margin production opportunities within our portfolio and we also delivered solid financial results as well. Our strong growth in oil production, combined with improved oil price realizations, drove our E&P upstream revenue to $2.7 billion in the second quarter. These factors increased oil sales to more than 60% of our total E&P revenue in the quarter, pushing overall upstream revenue 20% higher than the year-ago quarter.

Not only are our upstream revenues growing rapidly, but our midstream profitability is expanding as well. In the second quarter, our midstream business delivered excellent results, generating $224 million of operating profit. This result exceeded the top end of our guidance range and represented a 90% increase compared to the second quarter of last year. The year-over-year increase in operating profit was driven by the consolidation of EnLink Midstream and improved marketing margins. Based on our outstanding results in the first half of the year, we are increasing our full-year forecast for midstream operating profit to a range of $775 to $825 million, an increase of roughly $80 million from the midpoint of our previous guidance.

Moving to expenses…In the second quarter, total pre-tax cash costs were well within our guidance range for the quarter, coming in at $1.1 billion. Excluding the costs associated with the consolidation of EnLink Midstream, pre-tax cash costs for our upstream business were 7% higher than the second quarter of 2013. Of this amount, a third of the cost increase was attributable to higher operating costs associated with the Devon’s rapidly growing high-margin oil. The remaining increase was driven by higher production taxes related to our strong revenue growth. Looking to the second half of the year, we expect modest upward pressure on our pre-tax cash costs. This is reflected in our 8-K guidance that will be filed later today.

Overall, the benefits of our higher-margin oil production, improved price realizations and low cost structure significantly expanded our pre-tax cash margins. In fact, our pre-tax cash margins improved by 40 percent year over year to our highest level in recent history.

Moving to the bottom line…Our strong second quarter performance delivered adjusted earnings of $574 million or $1.40 per diluted share, a 16% increase compared to the same quarter last year. This improved profitability also translated into higher cash flows as well. We generated cash flow from operations of $2 billion, a 47% increase compared to the year-ago quarter, comfortably exceeding Wall Street expectations. Combined with $2.8 billion of pre-tax proceeds received from the sale of the company's Canadian conventional gas business in April, Devon's total cash inflows for the quarter reached $4.8 billion.

In late June, we repatriated the $2.8 billion of sale proceeds from Canada. We utilized these repatriated funds, the free cash flow generated during the quarter and cash on hand to reduce debt by $3.2 billion during the quarter. At June 30th, our net debt declined to $10.7 billion, of which $1.7 billion was attributable to the consolidation of EnLink Midstream and is non-recourse to Devon. If you were to pro forma the balance sheet for the closing of our U.S. divestitures, which should occur in the next few weeks, our net debt, excluding EnLink's debt, decreased to around $7.5

billion. To put this in better perspective, this is only around 1 times 2014 expected EBITDA. This positions the go-forward Devon with strong investment-grade credit ratings and one of the better balance sheets in the E&P space.

Moving to our outlook for the third quarter, we expect **our go-forward asset portfolio** to continue to demonstrate excellent year-over-year growth in oil production, with average daily oil rates ranging from 200,000 to 210,000 barrels per day. This guidance implies an expected 30-plus percent increase in oil production from our go-forward properties compared to the year-ago quarter. We expect to achieve this excellent growth in spite of the planned turnaround at Jackfish 1, which will limit production by 5,000 to 10,000 barrels per day in the third quarter. Overall, we expect **our go-forward asset portfolio** to deliver total production in the range of 603,000 to 627,000 BOE per day. This represents top-line growth from our retained assets of more than 10% compared to the third quarter of 2013.

Based on our solid execution during the first six months of this year, we remain very comfortable with our previous full-year guidance ranges for production. For the full year, we are on track to average more than 600,000 BOE per day from our go-forward business, driven by a full-year oil growth rate in excess of 30%.

And finally, as a reminder, we will file a Form 8-K later today containing detailed estimates for the upcoming third quarter and the full-year 2014. With that, I will turn the call back to Vince for Q&A. Vince?

Q&A Session

John Richels – President & Chief Executive Officer

Well folks, I am showing the top of the hour, but before signing off, I will leave you with a few key takeaways from today's call…

- First, we have dramatically improved our portfolio in a short period of time.
- Devon emerges with a formidable portfolio that is on track to deliver attractive high-margin production growth for many years to come.
- As evidenced by our Q2 results, our pursuit of high-margin production is significantly expanding our margins and profitability. And finally…
- The commitment to our top strategic objective to optimize long-term growth in debt-adjusted cash flow per share has never been stronger. As we deliver on our growth expectations, we are poised to create significant value for our shareholders in the upcoming years.

So we will look forward to talking with you again at the next call, and thank you for joining us today.

This document includes "forward-looking statements" as defined by the Securities and Exchange Commission (SEC). Such statements are those concerning strategic plans, expectations and objectives for future operations. All statements, other than statements of historical facts, included in this press release that address activities, events or developments that the company expects, believes or anticipates will or may occur in the future are forward-looking statements. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the company. Statements regarding future drilling and production are subject to all of the risks and uncertainties normally incident to the exploration for and development and production of oil and gas. These risks include, but are not limited to, the volatility of oil, natural gas and NGL prices; uncertainties inherent in estimating oil, natural gas and NGL reserves; the extent to which we are successful in acquiring and discovering additional reserves; unforeseen changes in the rate of production from our oil and gas properties; uncertainties in future exploration and drilling results; uncertainties inherent in estimating the cost of drilling and completing wells; drilling risks; competition for leases, materials, people and capital; midstream capacity constraints and potential interruptions in production; risk related to our hedging activities; environmental risks; political or regulatory changes; and our limited control over third parties who operate our oil and gas properties. Investors are cautioned that any such statements are not guarantees of future performance and that actual results or developments may differ materially from those projected in the forward-looking statements. The forward-looking statements in this press release are made as of *the date of this press release, even if subsequently made available by Devon on its website or otherwise. Devon does not undertake any obligation to update the forward-looking statements as a result of new information, future events or otherwise.*

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves that meet the SEC's definitions for such terms, and price and cost sensitivities for such reserves, and prohibits disclosure of resources that do not constitute such reserves. This release may contain certain terms, such as resource potential and exploration target size. These estimates are by their nature more speculative than estimates of proved, probable and possible reserves and accordingly are subject to substantially greater risk of being actually realized. The SEC guidelines strictly prohibit us from including these estimates in filings with the SEC. U.S. investors are urged to consider closely the disclosure in our Form 10-K, available at www.devonenergy.com. You can also obtain this form from the SEC by calling 1-800-SEC-0330 or from the SEC's website at www.sec.gov.